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INCREASED OIL PRODUCTION AND RESERVES UTILIZING SECONDARY/TERTIARY RECOVERY TECHNIQUES ON SMALL RESERVOIRS IN THE PARADOX BASIN, UTAH

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By
Thomas C. Chidsey, Jr.
M. Lee Allison

July 1998

Performed Under Contract No. DE-FC22-95BC14988

Utah Geological Survey
Salt Lake City, Utah

National Petroleum Technology Office
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Increased Oil Production And Reserves Utilizing Secondary/Tertiary Recovery Techniques On Small Reservoirs In The Paradox Basin, Utah

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Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Rhonda Lindsey, Technology Manager
National Petroleum Technology Office
P.O. Box 3628
Tulsa, OK 74101

Prepared by:
Utah Geological Survey
1594 West North Temple, Suite 3110
Salt Lake City, UT 84114-6100

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ABSTRACT

The Paradox basin of Utah, Colorado, and Arizona contains nearly 100 small oil fields producing from carbonate buildups or mounds within the Pennsylvanian (Desmoinesian) Paradox Formation. These fields typically have one to four wells with primary production ranging from 700,000 to 2,000,000 barrels (111,300-318,000 m^3) of oil per field at a 15 to 20 percent recovery rate. At least 200 million barrels (31,800,000 m^3) of oil are at risk of being unrecovered in these small fields because of inefficient recovery practices and undrained heterogeneous reservoirs. Five fields (Anasazi, Mule, Blue Hogan, Heron North, and Runway) within the Navajo Nation of southeastern Utah are being evaluated for waterflood or carbon-dioxide (CO_2)-miscible flood projects based upon geological characterization and reservoir modeling. The results can be applied to other fields in the Paradox basin and the Rocky Mountain region, the Michigan and Illinois basins, and the Midcontinent.

Geological characterization on a local scale focused on reservoir heterogeneity, quality, and lateral continuity as well as possible compartmentalization within each of the five project fields. This study utilized representative core and modern geophysical logs to characterize and grade each of the five fields for suitability of enhanced recovery projects. The typical vertical sequence or cycle of lithofacies from each field, as determined from conventional core, was tied to its corresponding log response.

The diagenetic fabrics and porosity types found in the various hydrocarbon-bearing rocks of each field can be an indicator of reservoir flow capacity, storage capacity, and potential for water- and/or CO_2-flooding. Diagenetic histories of the various Desert Creek reservoirs were determined from 50 representative samples selected from the conventional cores of each field. Thin sections were also made of each sample for petrographic description.

Three generalized facies belts are present in the Desert Creek zone of the Paradox Formation: (1) open-marine, (2) shallow-shelf and shelf-margin, and (3) intra-shelf, salinity-restricted facies. The shallow-shelf and shelf-margin facies belt, where all five project fields are located, includes shallow-shelf carbonate buildups, platform-margin calcarenites, and platform-interior carbonate muds and sands. The platform-margin calcarenite facies are located along the margins of the larger shallow shelf or the rims of phylloid-algal buildup complexes. Facies mapping indicates a relatively untested belt of shallow-shelf, calcarenite carbonate deposits.

Isochron maps, based on new seismic data indicated Mule field is a lenticular, north to northeast-trending, linear mound with additional reservoir potential on strike to the northeast of the most productive well in the field, the Mule No. 31-M. Harken Southwest Corporation, the field operator, determined the most economical way to penetrate a significant portion of this potential mound buildup was to re-enter the Mule No. 31-K-1 (N) well and drill horizontally in a northwest direction. The Mule No. 31 K-1 sidetrack, with a horizontal displacement of 939 feet (286 m), was the first horizontal test of a small algal buildup in the Paradox basin. Some zones of intercrystalline porosity in dolomites and black residual oil staining observed in the cuttings led the operator to attempt a open-hole well completion which finalized at a rate of 149 bbls (24 m^3) of oil and 223 bbls (35 m^3) of water per day respectively.

The Anasazi field was selected for the initial geostatistical modeling and reservoir simulation. The key to increasing ultimate recovery from the Anasazi field (and similar fields in the basin), is to design either waterflood or CO_2-miscible flood projects capable of forcing oil from high-storage-capacity but low-recovery supra-mound units into the high-recovery mound-core units.

Statistical modeling included architectural, porosity, and 15-layer models. The results were used in reservoir simulations to test and design waterflood or CO_2-miscible flood projects.

The reservoir analysis for the Anasazi field required a field-scale reservoir simulator. Enhanced recovery through CO_2 flooding and water-flooding were evaluated using a compositional simulation. Variations in carbonate lithotypes, porosity, and permeability were incorporated into the simulation in order to accurately predict reservoir response. History matches were made by tying to previous production and reservoir pressure history so that future reservoir performance could be confidently predicted. Economic assessments were conducted for CO_2 flooding in Anasazi field. Initial results of this economic assessment indicate continuous CO_2 injection without gas processing has merit and support continued evaluation of algal-mound reservoirs as potential CO_2-flood candidates.

The Desert Creek carbonate-mound buildup reservoir at Runway field was selected for a follow-up study to the completed Anasazi field reservoir assessment both for comparison with those results, and also as a more promising candidate for a Phase II pilot demonstration due to the closer proximity of Runway to potential sources of injectable CO_2. As at Anasazi field, significant heterogeneity in both the lithotypes and the reservoir properties at Runway field required development of a multi-stage procedure for incorporating the variation known to exist in conventional cores from the field into the reservoir geostatistical model. Geostatistical modeling of the Runway reservoir incorporated unit thicknesses, flooding surfaces, and lithotypes observed in the core. A compositional simulation approach is being used to model: (1) primary depletion (history match), (2) waterflood, and (3) CO_2-flood processes.

Technology transfer during the second project year consisted of booth displays for various national and regional professional conventions, technical presentations, publications, newsletters, and a project home page on the Internet.

EXECUTIVE SUMMARY

The primary objective of this project is to enhance domestic petroleum production by demonstration and technology transfer of an advanced-oil-recovery technology in the Paradox basin, southeastern Utah. If this project can demonstrate technical and economic feasibility, the technique can be applied to approximately 100 additional small fields in the Paradox basin alone, and result in increased recovery of 150 to 200 million barrels (23,850,000-31,800,000 m^3) oil. This project is designed to characterize five shallow-shelf carbonate reservoirs in the Pennsylvanian (Desmoinesian) Paradox Formation and choose the best candidate for a pilot demonstration project for either a waterflood or carbon-dioxide-(CO_2-) flood project. The field demonstration, monitoring of field performance, and associated validation activities will take place within the Navajo Nation, San Juan County, Utah.

The Utah Geological Survey (UGS) leads a multidisciplinary team to determine the geological and reservoir characteristics of typical small shallow-shelf carbonate reservoirs in the Paradox basin. The Paradox basin project team consists of the UGS (prime contractor), Harken Southwest Corporation, and several subcontractors. This research is performed under the Class II Oil Program of the U.S. Department of Energy, National Petroleum Technology Office (NPTO) in Tulsa, Oklahoma. This report covers research and technology transfer activities for the third project year (February 9, 1997 through February 8, 1998). This work includes analysis of diagenetic fabrics, mapping a new exploration trend, horizontal drilling, geostatistical modeling, production history matching, reservoir performance prediction, and economic assessments of secondary/tertiary recovery options. The results can be applied to similar reservoirs in many U.S. basins.

Reservoir data, cores and cuttings, geophysical logs, various reservoir maps, and other information from the project fields and regional exploratory wells are being collected. Well locations, production reports, completion tests, core analysis, formation tops, and other data were compiled and entered in a database developed by the UGS. Cores were described from selected project wells with special emphasis on bounding surfaces of possible flow units. The typical vertical sequence or cycle of lithofacies from each field, as determined from conventional core, was tied to its corresponding log response.

The diagenetic fabrics and porosity types found in the various hydrocarbon-bearing rocks of each field can be an indicator of reservoir flow capacity, storage capacity, and potential for water- and/or CO_2-flooding. Diagenetic histories of the various Desert Creek reservoirs were determined from 50 representative samples selected from the conventional cores of each field. Thin sections were also made of each sample for petrographic description. Most reservoirs in the project fields have a mixing zone as well as a fresh water overprint. Within the vadose and meteoric phreatic zones, neomorphism, leaching/dissolution, and fresh water cementation (dog tooth, stubby, and small equant calcite) has taken place. Those fields that had a portion of the carbonate buildup facing the open marine environment, generally a steep wall complex, developed early-marine cements (such as fibrous isopachous, botryoidal, and radiaxial cements). Many reservoirs contain two generations of dolomite from seepage reflux by brines from bordering hypersaline lagoons. Anhydrite replacement and bitumen plugging are also common.

Regionally three generalized facies belts were identified: (1) open-marine, (2) shallow-shelf and shelf-margin, and (3) intra-shelf, salinity-restricted facies. All five project fields, as well as the other Desert Creek fields in the region, are located within the shallow-shelf and shelf-margin facies belt. This facies belt includes shallow-shelf carbonate buildups, platform-margin calcarenites, and

platform-interior carbonate muds and sands. The platform-margin calcarenite facies are located along the margins of the larger shallow shelf or the rims of phylloid-algal buildup complexes. Mapping indicates a relatively untested belt of shallow-shelf, calcarenite carbonate deposits. Heron North field is an excellent example of the type of fields which potentially lie within this 20-mile-(32-km-)long lithofacies belt. These reservoirs likely have excellent overall reservoir properties and are good candidates for water/CO_2 floods.

Isochron maps, based on new seismic data, indicated Mule field is a lenticular, north to northeast-trending, linear mound with additional reservoir potential on strike to the northeast of the most productive well in the field, the Mule No. 31-M. Harken Southwest Corporation, the field operator, determined the most economical way to penetrate a significant portion of this potential mound buildup was to re-enter the Mule No. 31-K-1 (N) well and drill horizontally in a northwest direction. The Mule No. 31 K-1 sidetrack, with a horizontal displacement of 939 feet (286 m), was the first horizontal test of a small algal buildup in the Paradox basin. Well cuttings and the mud log indicated possible intercrystalline porosity zones in the supra-mound interval of the buildup facies, lagoonal overwash deposits (?), and mound-front facies. The operator completed the well open hole; the well was finalized at a rate of 149 bbls (24 m^3) of oil and 223 bbls (35 m^3) of water per day respectively.

Of the five carbonate buildup fields in the Desert Creek zone originally identified as candidates for detailed study, the Anasazi field was selected for the initial geostatistical modeling and reservoir simulation. The key to increasing ultimate recovery from the Anasazi field (and similar fields in the basin), is to design either waterflood or CO_2-miscible flood projects capable of forcing oil from high-storage-capacity but low-recovery supra-mound units into the high-recovery mound-core units. The significant heterogeneity in both the lithotypes and the reservoir properties at Anasazi field requires development of a multi-stage procedure for incorporating the variation known to exist in conventional cores from Anasazi field and outcrop analogues into the reservoir geostatistical model. Statistical modeling included architectural, porosity, and 15-layer models.

The internal architecture of the reservoir between the wells was modeled using a marked point (Boolean) process for emplacement of 10 constituent lithotypes. Emplacement sequences were established and the relative lithotype proportions varied stochastically. The pair-wise block-exchange process for simulating reservoir porosity between the Anasazi wells was carried out using a stochastic relaxation technique known as simulated annealing. Sensitivity studies were conducted which indicated that most of the variation in effective reservoir properties could be retained with careful scaling of porosity and permeability. Lithotypes were assigned to gridblocks in 15-layers. Porosity was volume-averaged for the 15-layer model, and effective permeability was computed by solution of the pressure equation using the field-scale reservoir simulator. The results of these statistical models were used in reservoir simulations to test and design water-and/or CO_2-flooding projects.

A compositional simulation approach, requiring a field-scale, three-dimensional reservoir simulator, was used to model primary depletion, waterflood, and CO_2-flood processes for Anasazi field. Enhanced recovery through CO_2 flooding and water-flooding were evaluated using a compositional simulation. History matches were made by tying to previous production and reservoir pressure history so that future reservoir performance could be confidently predicted.

The series of waterflood predictions assessed the placement and completion configuration of injection wells and the use of horizontal injector wells versus vertical injector wells. In general, injection of water had a detrimental effect on continued production during reservoir fill up. The poor performance of waterflooding is attributable to the low injectivity of water and the interference with oil migration into the mound-core interval from the supra-mound interval from both the mound and off-mound areas.

Economic assessments were conducted for CO_2 flooding in Anasazi field. Initial results of this economic assessment indicate continuous CO_2 injection without gas processing has merit and support continued evaluation of algal-mound reservoirs as potential CO_2-flood candidates. Production data and injection gas requirements were used to assess, from an economic standpoint, the financial merits of CO_2 flood with a 8.0 MMCFGPD (226,560 m^3/d) total injection rate commencing January 1, 2000. This assessment concluded that CO_2 flooding provides both an adequate flood response and an acceptable economic rate of return of 32 percent and a payout of 36 months. A discounted (10 percent) net present value of $5.9 million could be realized by implementing a CO_2 flood.

The Desert Creek carbonate-mound buildup reservoir at Runway field was selected for a follow-up study to the completed Anasazi field reservoir assessment both for comparison with those results, and also as a more promising candidate for a Phase II pilot demonstration due to the closer proximity of Runway to potential sources of injectable CO_2. However, the reservoir also is more gas rich than the other project fields and consists of both phylloid-algal and bryozoan buildup facies. As at Anasazi field, significant heterogeneity in both the lithotypes and the reservoir properties at Runway field required development of a multi-stage procedure for incorporating the variation known to exist in conventional cores from the field into the reservoir geostatistical model.
Geostatistical modeling of the Runway reservoir incorporated unit thicknesses, flooding surfaces, and lithotypes observed in the core. A total of nine lithotypes were recognized from the Runway cores, which formed the basis for generating an architectural model of the Desert Creek reservoir, using a boolean marked-point process for lithotype emplacement between the wells. These reservoir partitions were then populated with porosities, using layer-averaged statistical distributions obtained from the well log and core data. The spatial distribution of porosity was fitted to an average porosity grid using a constrained stochastic block-exchange procedure (simulated annealing). Realizations representing the predominant types of connectivity were vertically scaled up to 10 layers, and short simulation sensitivity runs will be carried out to evaluate the impact of heterogeneity on reservoir behavior. The most representative of these cases will then be selected for conducting the compositional flow-simulation history match and reservoir performance predictions using waterflood, and CO_2-flood processes.

Technology transfer during the third project year consisted of displaying project materials at the UGS booth during the national and regional conventions of the American Association of Petroleum Geologists. In addition, four technical presentations were made to geological societies and NPTO staff. Project team members published abstracts, quarterly and annual reports, and newsletters detailing project progress and results. The UGS maintained a home page for the Paradox basin project on the Internet.

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Project Contributors:

Principal Investigator:	M.L. Allison; Utah Geological Survey, Salt Lake City, UT
Program Manager:	T.C. Chidsey, Jr.; Utah Geological Survey, Salt Lake City, UT
Financial Officers:	Werner Haidenthaller, Dan Kelly; Utah Geological Survey, Salt Lake City, UT B.N. Huff; Harken Southwest Corp., Irving, TX

Contributing Scientists and Organizations:

R.L. Bon, T.C. Chidsey, Jr., K.P. McClure; Utah Geological Survey, Salt Lake City, UT

Rich Cottle, Joe Clarke, David Gibbs, Marshall Watson, Kris Hartmann; Harken Southwest Corp., Irving, TX

W.E. Culham, D.M. Lorenz; REGA Inc., Houston, TX

D.E. Eby; Eby Petrography & Consulting, Inc.; Littleton, CO

John Johnson of the Minerals Department, Navajo Nation, Window Rock, AZ, provided valuable advice and data. Brenda Kirkland George and Jonas Gournay of the University of Texas at Austin, described core from the Anasazi No. 1 well. Core photography was done by Carolyn Olsen and Ronald Neeley of the Utah Geological Survey Sample Library. Figures and report were produced by Michele Hoskins, Vicky Clarke, Jim Parker, and Sharon Hamre of the UGS.

This report or portions of it were reviewed by Bryce Tripp, Utah Geological Survey and Rhonda P. Lindsey, National Petroleum Technology Office, U.S. Department of Energy.

1. INTRODUCTION

Thomas C. Chidsey, Jr.; Utah Geological Survey

Over 400 million barrels (63,600,000 m^3) of oil have been produced from shallow-shelf carbonate reservoirs in the Pennsylvanian (Desmoinesian) Paradox Formation in the Paradox basin of Utah, Colorado, and Arizona. With the exception of the giant Greater Aneth field, 100-plus oil fields in the basin typically contain 2 to 10 million barrels (318,000-1,590,000 m^3) of original oil in place per field. To date, none of these small fields have been the site of secondary/tertiary recovery techniques used in large carbonate reservoirs. Most of these fields are characterized by extremely high initial production rates followed by a very short production life (primary) and hence early abandonment. At least 200 million barrels (31,800,000 m^3) of oil is at risk of being left behind in these small fields because of inefficient recovery practices and undrained heterogeneous reservoirs. The purpose of this multi-year project is to enhance domestic petroleum production by demonstration and technology transfer of an advanced-oil-recovery technology in the Paradox basin.

The benefits expected from the project are: (1) increasing recoverable reserves by identifying untapped compartments created by reservoir heterogeneity, (2) increasing deliverability through a waterflood or carbon-dioxide- (CO_2-) miscible flood which exploits the reservoir along optimal fluid-flow paths, (3) identifying reservoir trends for field extension drilling and stimulating exploration in Paradox basin fairways, (4) preventing premature abandonment of numerous small fields, (5) reducing development costs by more closely delineating minimum field size and other parameters necessary to a successful flood, (6) allowing limited energy investment dollars to be used more productively, and (7) increasing royalty income to the Navajo Nation; Federal, State, and local governments; and fee owners. These benefits also apply to other areas in the Rocky Mountain region, the Michigan and Illinois basins, and the Midcontinent.

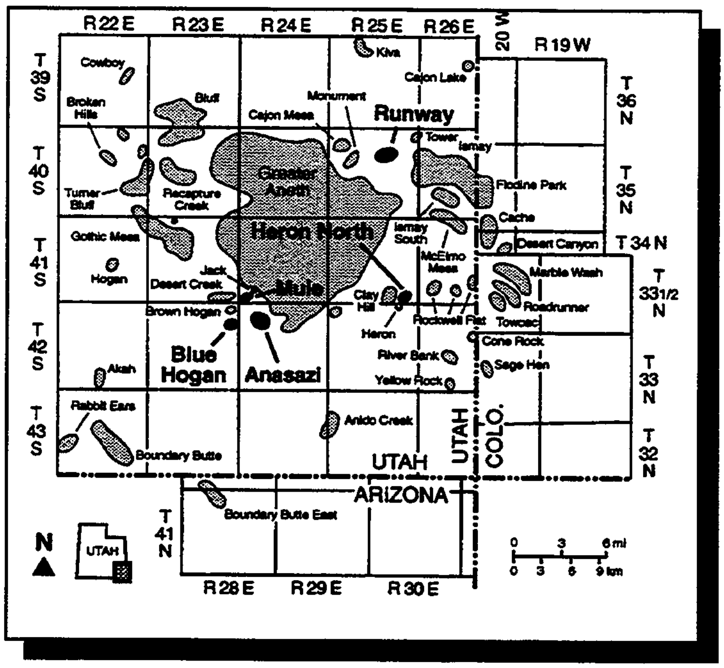


Figure 1.1. Location of project fields (dark shaded areas with names in bold type) in the southwestern Paradox basin on the Navajo Nation, San Juan Co., Utah.

The geological and reservoir characteristics of five fields (figure 1.1) which produce oil and gas from the Desert Creek zone of the Paradox Formation are being quantitatively determined by a multidisciplinary team. The best candidate for a pilot waterflood or CO_2-flood demonstration project will be chosen after reservoir simulations have been completed on the Anasazi and Runway fields. To evaluate these fields as models for other shallow-shelf carbonate reservoirs, the Utah Geological Survey (UGS), Harken Southwest Corporation, Eby Petrography & Consulting Inc., and REGA Inc. entered into a cooperative agreement with the U.S. Department of Energy as part of its Class II Oil program.

A two-phase approach is being used to increase production and reserves from the shallow-shelf carbonate reservoirs in the Paradox basin. Phase I is the geological and reservoir characterization of the five small fields. Work done during the third year and continuing into the fourth year of this phase includes:

(a) determining diagenetic fabrics and porosity types found in the various hydrocarbon-bearing rocks of each field,

(b) drilling the first horizontal development well on a small mound in the basin,

(c) mapping a relatively untested belt of shallow-shelf, calcarenite carbonate deposits,

(d) field-scale geologic analysis to focus on the reservoir heterogeneity, quality, and lateral continuity versus compartmentalization,

(e) extensive reservoir mapping,

(f) determining field reserves and secondary/tertiary recovery,

(g) evaluating oil-brine and gas-oil capillary pressure data and analyzing the Runway well tests,

(h) various laboratory tests and analogies to large scale waterfloods/CO_2 floods,

(i) history matching and reservoir simulations, and

(j) determining the economic viability of secondary/tertiary recovery options.

Phase II will be a demonstration project on the field selected from the characterization study using the secondary/tertiary recovery techniques identified as having the greatest potential for increased well productivity and ultimate recovery. The demonstration project will include:

(a) drilling a development well to facilitate sweep during the pilot flood,

(b) acquiring a CO_2 and/or water source for the flood project,

(c) installation of CO_2 and/or waterflood injection facilities,

(d) conversion of a producing well to injection,

(e) flood management, monitoring, and evaluation of results, and

(f) determining the application of the project to similar fields in the Paradox basin and throughout the U.S.

The results of this project are being transferred to industry and other researchers through a petroleum extension service, creation of digital databases for distribution, technical workshops and seminars, field trips, technical presentations at national and regional professional meetings, maintaining a project home page on the Internet, and publication in newsletters and various technical or trade journals.

This report is organized into five sections: (1) Introduction, (2) Geological Characterization of Project Fields and Horizontal Drilling Program, Navajo Nation, San Juan County, Utah, (3) Geostatistical Modeling and Reservoir Simulation, Anasazi Field, (4) Geostatistical Modeling and Reservoir Engineering Analysis, Runway Field, and (5) Technology Transfer. This report presents the progress of ongoing research and is not intended as a final report. Whenever possible, preliminary conclusions have been drawn based on available data.

2. GEOLOGICAL CHARACTERIZATION OF PROJECT FIELDS AND HORIZONTAL DRILLING PROGRAM, NAVAJO NATION, SAN JUAN COUNTY, UTAH

Thomas C. Chidsey, Jr., and Kevin McClure; Utah Geological Survey
Kris Hartmann and Marshall Watson; Harken Southwest Corp.
and
David E. Eby; Eby Petrography & Consulting, Inc.

The five Paradox basin fields being evaluated in Phase I of the project are Anasazi, Blue Hogan, Heron North, Mule, and Runway located within the Navajo Nation of southeast Utah (figure 1.1); they are five of several satellite carbonate mounds around the giant Greater Aneth field. This evaluation included data collection, core analysis and description, reservoir mapping, and drilling the second of possibly three development wells. The geological and reservoir characterization of these fields and resulting models can be applied to similar fields in the basin (and other basins as well) where data might be limited. The following presents the results of these efforts during the third year of the project.

2.1 Field Data Collection and Compilation

Reservoir data, cores and cuttings, geophysical logs, various reservoir maps, and other information from the project fields and regional exploratory wells continued to be collected by the UGS. Well locations, production reports, completion tests, core analysis, formation tops, and other data were compiled and entered in a database developed by the UGS. This database, INTEGRAL*gim, is a geologic-information database that links a diverse set of geologic data to records using PARADOX™ for DOS software. The database is designed so that geological information, such as lithology, petrophysical analyses, or depositional environment can be exported to software programs to produce strip logs, lithofacies maps, various graphs, statistical models, and other types of presentations. Production data, basic core analyses, geophysical log types, and well cutting information for these project wells have been entered into the UGS INTEGRAL*gim database. In addition, completion test data and formation tops have also been entered into the database for these wells. The database containing information from the project will be available as a UGS open-file (digital format) report at the conclusion of Phase I (the geological and reservoir characterization study).

Cores were described from selected project wells with special emphasis on bounding surfaces of possible flow units. The core descriptions follow the guidelines of Bebout and Loucks (1984) which include: (1) basic porosity types, (2) mineral composition in percentage, (3) nature of contacts, (4) carbonate structures, (5) carbonate textures in percentage, (6) carbonate fabrics, (7) grain size (dolomite), (8) fractures, (9) color, (10) fossils, (11) cement, and (12) depositional environment. Carbonate fabrics were determined according to Dunham's (1962) and Embry and Klovan's (1971) classification schemes.

Geological characterization on a local scale focused on reservoir heterogeneity, quality, and lateral continuity as well as possible compartmentalization within each of the five project fields. This study utilized representative core and modern geophysical logs to characterize and grade each of the five fields for suitability of enhanced recovery projects.

The typical vertical sequence or cycle of lithofacies from each field, as determined from conventional core, was tied to its corresponding log response (figures 2.1-2.5). These sequences graphically include: (1) carbonate fabric, pore type, physical structures, texture, framework grains, and facies (as defined by Chidsey and others, 1996; Chidsey, 1997) described from core, (2) plotted porosity and permeability analysis from core plugs, and (3) gamma-ray and neutron-density curves from geophysical logs. The graphs can be used for identifying reservoir and non-reservoir rock, determining potential units suitable for water- and/or CO_2-flood projects, and comparing field to non-field areas.

2.2 Reservoir Diagenesis

The diagenetic fabrics and porosity types found in the various hydrocarbon-bearing rocks of each field can be an indicator of reservoir flow capacity, storage capacity, and potential for water and/or CO_2 flooding. In order to determine the diagenetic histories of the various Desert Creek reservoirs, 50 representative samples were selected from the conventional cores of each field for geochemical analysis. Thin sections were also made of each sample for petrographic description. Typical geochemical and petrographic techniques that will be employed include: (1) epi-fluorescence and cathodoluminescence petrography to determine the sequence of diagenesis, (2) stable carbon and oxygen isotope analysis of diagenetic components such as cementing minerals and different generations of dolomites, (3) strontium isotopic analysis for tracing the origin of fluids responsible for different diagenetic events, (4) scanning electron microscopic analysis of various dolomites to determine reservoir quality of the dolomites as a function of diagenetic history, and (5) analysis of bitumen plugging pore throats. Each core was photographed (figure 2.6) and additional close-up photos were taken of: (1) typical moldic, vuggy, dolomitized, karst-brecciated, stylolitic as well as preserved primary porosity styles, (2) visible cement types, (3) sedimentary structures, and (4) pore plugging anhydrite and halite.

All depositional, diagenetic, and porosity information is being placed into the context of the production history to date, of each field in order to construct a detailed overview for each enhanced recovery candidate. Of special interest is the determination of the most effective pore systems for oil drainage versus storage.

2.2.1 Diagenetic Environments

Most shallow-shelf/shelf margin carbonate buildups or mounds had topographic relief which was subaerially exposed when sea level dropped. This produced four major diagenetic environments: (1) fresh water (meteoric) vadose zone (above the water table, generally at or near sea level), (2) meteoric phreatic zone (below the water table), (3) marine phreatic zone, and (4) mixing zone (Longman, 1980). The "iceberg" principle (the Ghyben-Herzberg theory), which states that for every foot the water table rises above sea level there may be 20 feet (6.1 m) of fresh water below

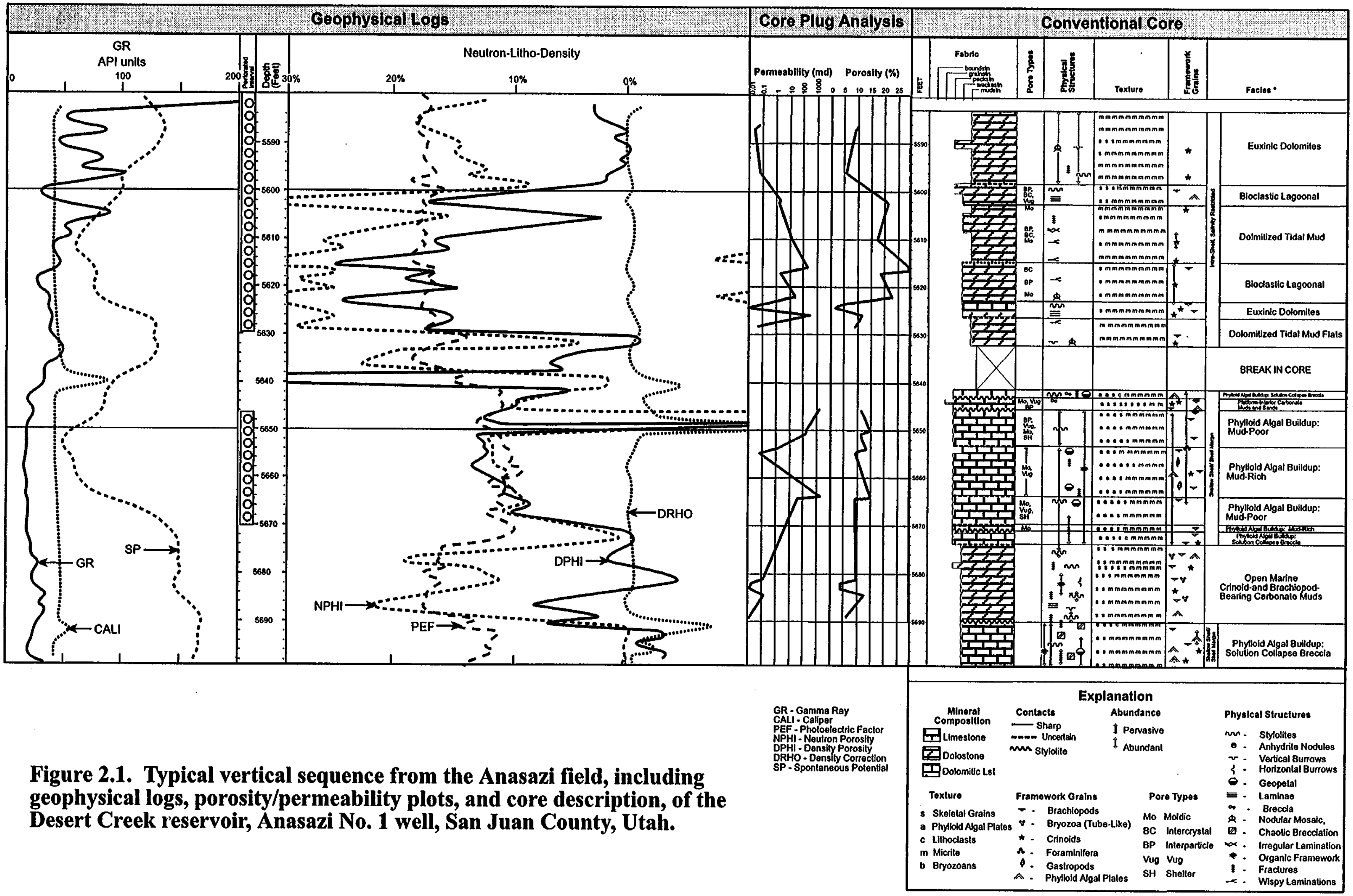
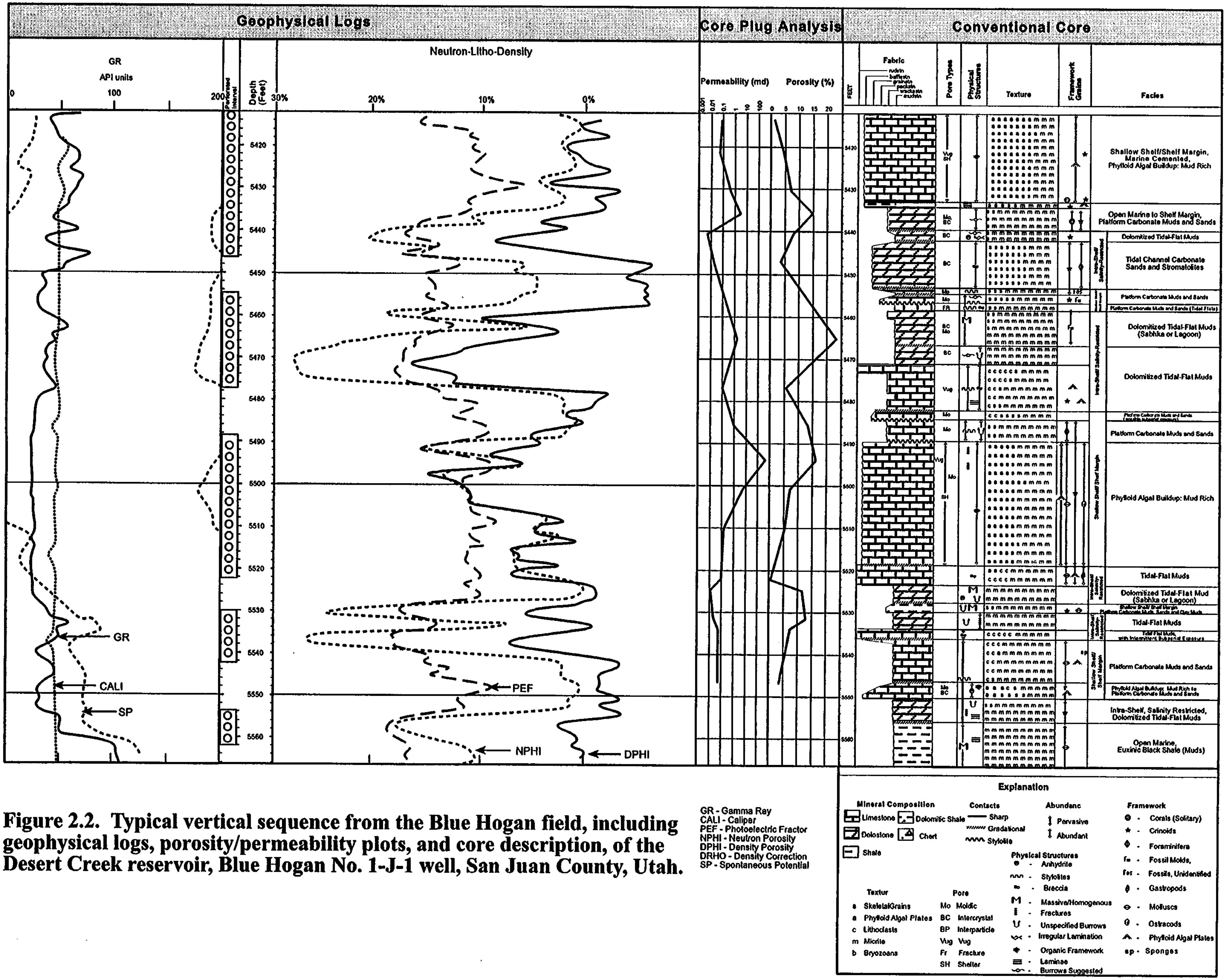


Figure 2.1. Typical vertical sequence from the Anasazi field, including geophysical logs, porosity/permeability plots, and core description, of the Desert Creek reservoir, Anasazi No. 1 well, San Juan County, Utah.



GR - Gamma Ray
CALI - Caliper
PEF - Photoelectric Fractor
NPHI - Neutron Porosity
DPHI - Density Porosity
DRHO - Density Correction
SP - Spontaneous Potential

Figure 2.2. Typical vertical sequence from the Blue Hogan field, including geophysical logs, porosity/permeability plots, and core description, of the Desert Creek reservoir, Blue Hogan No. 1-J-1 well, San Juan County, Utah.

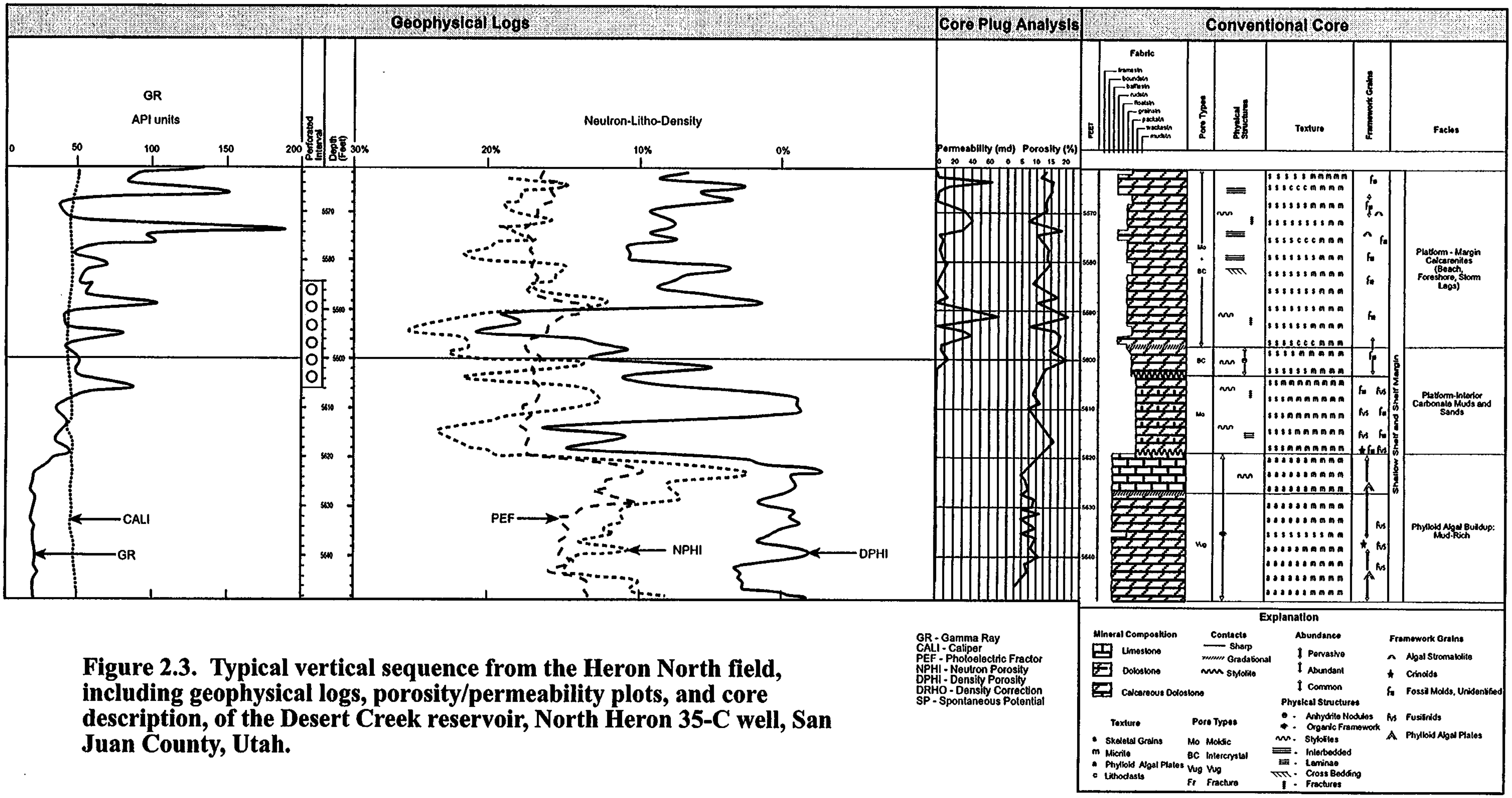


Figure 2.3. Typical vertical sequence from the Heron North field, including geophysical logs, porosity/permeability plots, and core description, of the Desert Creek reservoir, North Heron 35-C well, San Juan County, Utah.

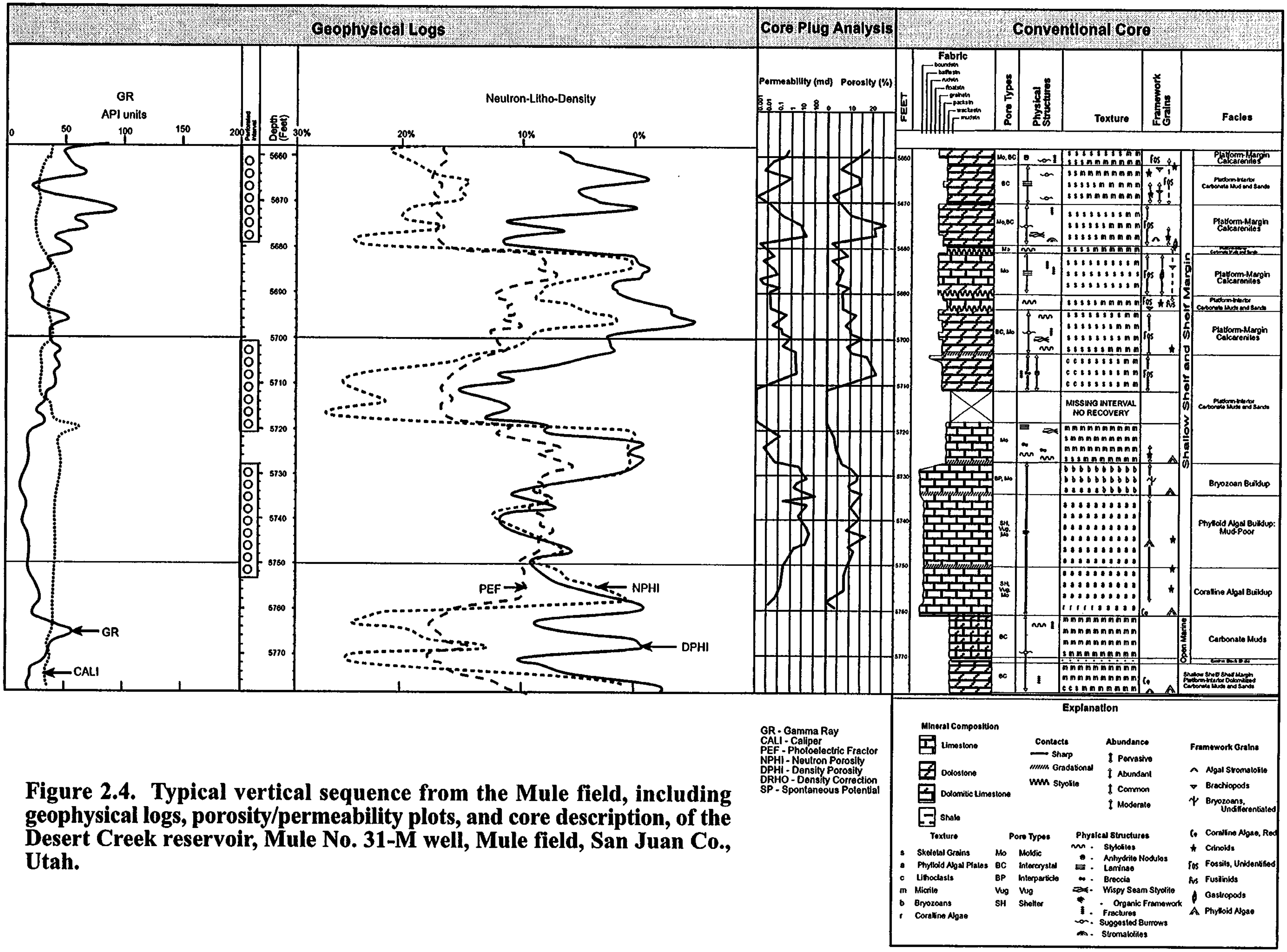


Figure 2.4. Typical vertical sequence from the Mule field, including geophysical logs, porosity/permeability plots, and core description, of the Desert Creek reservoir, Mule No. 31-M well, Mule field, San Juan Co., Utah.

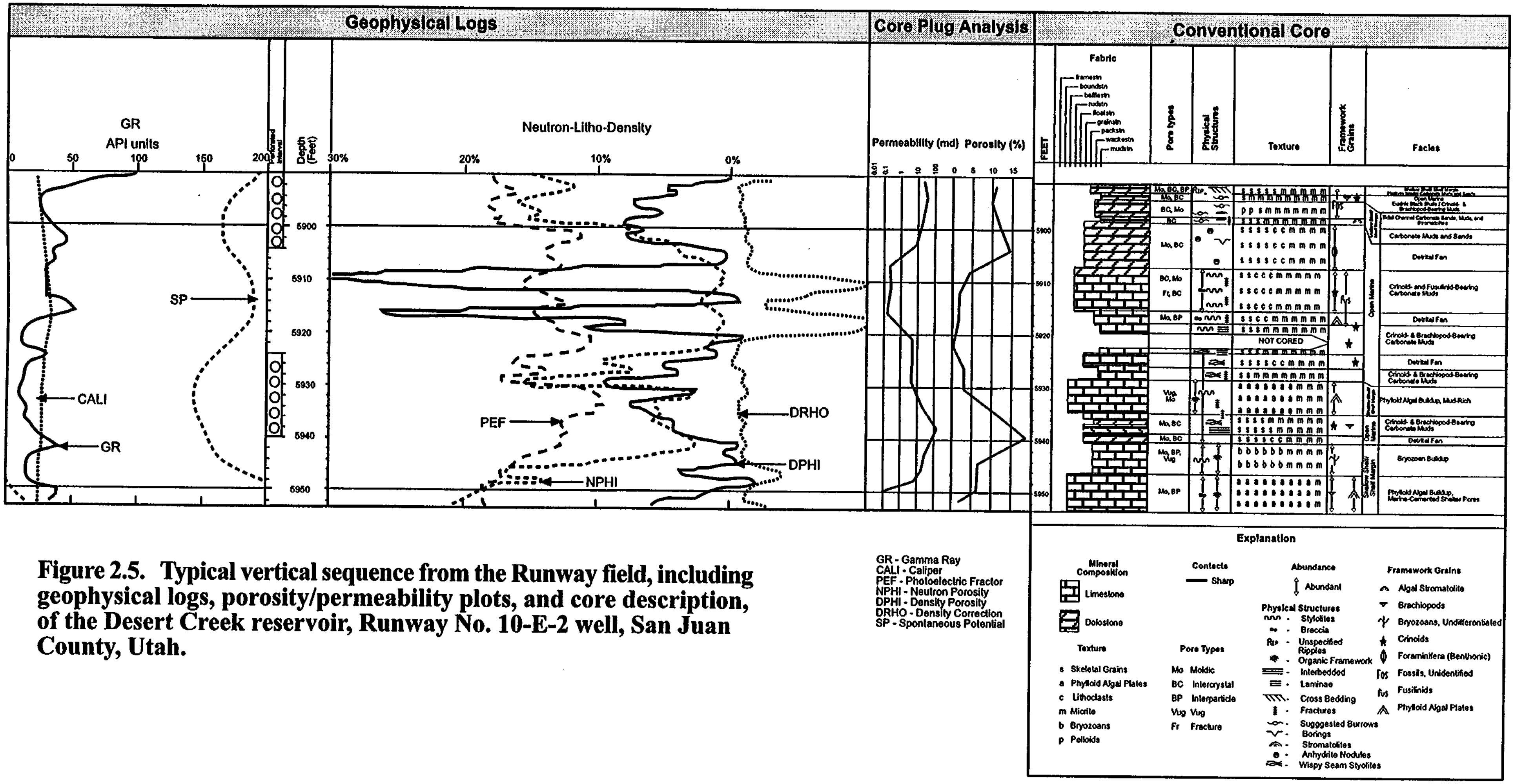


Figure 2.5. Typical vertical sequence from the Runway field, including geophysical logs, porosity/permeability plots, and core description, of the Desert Creek reservoir, Runway No. 10-E-2 well, San Juan County, Utah.

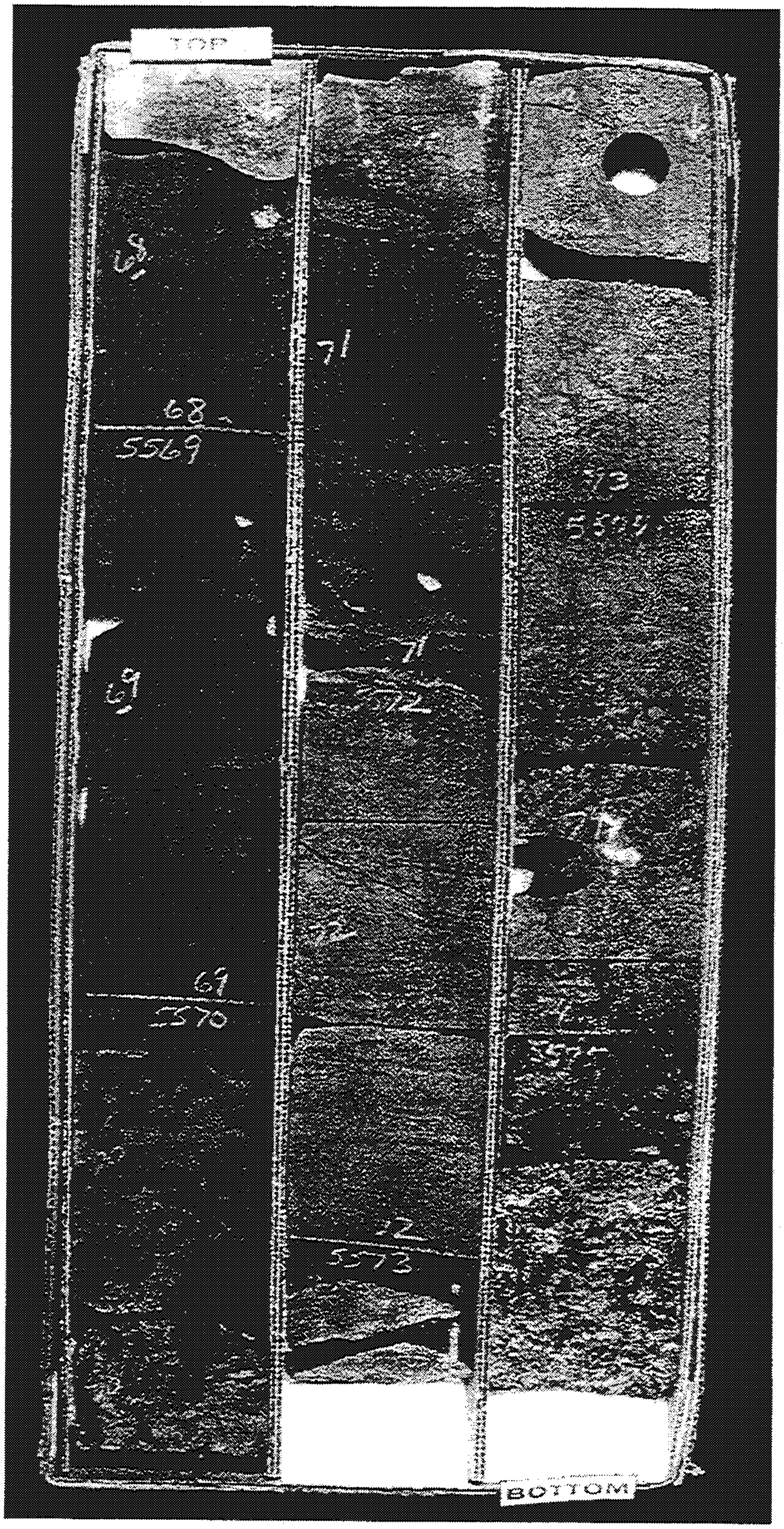


Figure 2.6. Core photograph of the highly dolomitized, oil-saturated calcarenite section of the North Heron No. 35-C well, Heron North field. Photo by C.M. Olsen, UGS.

the water table can generally be applied to both carbonate mound and island buildups (Friedman and Sanders, 1978). Neomorphism, leaching/dissolution, and fresh water cementation (dog tooth, stubby, and small equant calcite) take place within the vadose and meteoric phreatic zones.

Both the meteoric phreatic zone and marine phreatic zone are dynamic, changing with sea level fluctuations. These phreatic zones are separated by a mixing zone (fresh and sea water) which also changes with sea level fluctuation. Early dolomitization takes place in the mixing zone. Most carbonate buildups (fields) have a mixing zone as well as a fresh water overprint.

That portion of the carbonate buildup facing the open-marine environment is generally a steep-wall complex where early-marine cements (such as fibrous isopachous, botryoidal, and radiaxial cements) are deposited from invading sea water pumping through the system. The other side of the mound typically borders a hypersaline lagoon. The dense brine from the lagoon can seep into the phreatic zone, a process termed seepage reflux, forming a wedge-shaped zone of low-temperature dolomite deposition; both early replacement dolomite and dolomite cement.

2.2.2 Anasazi Field

The producing mud-poor to mud-rich, mound-core interval (5,646 to 5,670 feet [1,721-1,728 m]) in the Anasazi field is a limestone with a packstone to bafflestone fabric (figure 2.1). Framework grains consist of phylloid algal plates (dominating), brachiopods, bryozoans, pelloids, ostracods, and forams. Early marine cement is present and a limited amount of fresh water influence is indicated either from the vadose zone or outside the fresh water (phreatic) zone resulting in some fresh water cement. There is some bitumen plugging and anhydrite replacement. The diagenetic events occurred in the following order: (1) fibrous isopachous early marine cementation, (2) some stubby to equant to dog tooth spar cementation in shelter pores or molds, (3) saddle dolomite cementation, (4) anhydrite replacement, and (5) bitumen plugging. The basic pore types are primary shelter pores and secondary moldic pores. The reservoir has excellent flow capacity because much of the primary porosity and permeability was preserved.

The producing supra-mound interval (5,582 to 5,630 feet [1,701-1,716 m]) is a dolomite with a packstone to grainstone fabric (figure 2.1). Framework grains consist of coated skeletal grains and pelloids. A significant fresh water influence is indicated by the presence of degrading neomorphism and leaching. Dolomitization occurred in the mixing zone or from seepage reflux. There is some anhydrite plugging. The diagenetic events occurred in the following order: (1) degrading neomorphism, (2) dissolution, (3) early replacement dolomitization, (4) saddle dolomite cementation, and (5) anhydrite plugging. The basic pore types are primary interparticle pores and secondary moldic pores. The reservoir has an excellent storage flow capacity and is a candidate for CO_2 flooding because the overall diagenetic events increased porosity.

2.2.3 Blue Hogan Field

The producing mud-rich, mound-core interval (5,412 to 5,446 feet [1,650-1,600 m]) in the Blue Hogan field is a limestone with a bafflestone fabric (figure 2.2). Framework grains consist of phylloid algal plates with dolomite sphericals replacing utricules (original microstructures of phylloid algae). The buildup represents a high-energy reef wall which resulted in pervasive early marine cementation throughout what originally had been rock with high porosity. There is also some anhydrite replacement. The typical diagenetic events occurred in the following order: (1) first generation micrite and fibrous isopachous early marine cementation, (2) second generation botryoidal early marine cementation, (3) third generation radiaxial early marine cementation, (4) post-burial replacement rhombic dolomite cementation, (5) equant calcite cementation, and (6) anhydrite replacement. The basic pore types are primary shelter pores now filled with cement; and secondary moldic and channel pores. The reservoir has a moderate flow capacity because the pervasive amounts of cement.

2.2.4 Heron North Field

The producing platform-margin calcarenite interval (5,584 to 5,606 feet [1,702-1,709 m]) is a dolomite with a grainstone fabric (figure 2.3). Framework grains consist mainly of pelloids, surficial ooids, and coated skeletal grains deposited in a high-energy, beach depositional environment. Classic fresh water diagenesis or near-surface meteoric overprinting suggests early burial associated with an island. Dolomitization most likely resulted from seepage reflux. There is both anhydrite and bitumen plugging. The diagenetic events occurred in the following order: (1) degrading neomorphism, (2) dissolution by fresh water, (3) early first generation replacement dolomitization (fine grain dolomite), (4) second generation of dolomitization (coarse grain), (5) anhydrite replacement and plugging, and (6) bitumen plugging. The basic pore types are secondary moldic, intercrystalline, micro-intercrystalline, and channel pores. The reservoir has an excellent storage flow capacity and is a candidate for CO_2 flooding due to enhanced porosity from dolomitization.

2.2.5 Mule Field

The producing mud-poor, mound-core interval (5,728 to 5,753 feet [1,746-1,753 m]) is a limestone with a bafflestone fabric (figure 2.4). Framework grains consist of phylloid algal plates and bryozoans. Some early marine cement and minor fresh water cements are present. There is both silica and anhydrite replacement. The typical diagenetic events occurred in the following order: (1) minor fibrous isopachous early marine cementation, (2) minor dissolution and dog tooth cementation by fresh water, (3) post-burial equant calcite cementation, (4) late saddle dolomite cementation in molds replacing calcite cement, (5) some silicification, and (6) anhydrite replacement. The basic pore types are primary shelter and interparticle pores; and secondary moldic pores. The reservoir has an excellent flow capacity because primary porosity has been preserved.

The producing supra-mound interval (5,660 to 5,680 feet [1,725-1,731 m]) is a dolomite with a skeletal packstone to grainstone fabric (figure 2.1). Framework grains consist of bryozoans and phylloid algal plates. A heavy fresh water influence is indicated by the presence of degrading neomorphism and leaching, often seen as a solution front. Dolomitization occurred in the mixing zone or from seepage reflux. There is some anhydrite cement and bitumen plugging. The diagenetic events occurred in the following order: (1) degrading neomorphism, (2) dissolution, (3) dog tooth spar cementation, (4) early replacement dolomitization, (5) plugging of pores by late dolomite, calcite, and anhydrite cements, and (6) bitumen plugging. The basic pore types are secondary channel, moldic, intercrystalline, and micro-intercrystalline pores. The reservoir has a good storage flow capacity from secondary porosity development and is a candidate for CO_2 flooding.

2.2.6 Runway Field

The bryozoan buildup interval (5,940 to 5,946 feet [1,810-1,815 m]) is a limestone with a high energy grainstone fabric (figure 2.5). Framework grains consist of bryozoans, crinoids, phylloid algal plates, bivalves, forams, and clasts produced by brecciation. Some early marine cement and mixing zone dolomite (two generations) are present as well as anhydrite replacement. The typical diagenetic events occurred in the following order: (1) minor early marine cementation, (2) dog tooth and equant calcite cementation, (3) syntaxial cementation, (4) mechanical brecciation producing clasts, (5) first generation (early) dolomitization - medium-sized crystals, (6) second generation (late) dolomitization - very coarse crystals, (7) later saddle dolomite cementation, and (8) anhydrite replacement. The basic pore types are primary interparticle pores; and secondary intercrystalline and moldic pores. The reservoir has a good flow capacity based on the amount of porosity and permeability development.

The producing supra-mound interval (5,890 to 5,904 feet [1,795-1,800 m]) is a dolomite (100 percent) with a grainstone fabric (figure 2.5). Framework grains consist of ooids, pelloids, grain aggregates, ostracods, and some phylloid algal plates deposited in a high energy, shallow water to beach environment. A heavy fresh water influence is indicated by the presence of degrading neomorphism and patchy dissolution. Dolomitization occurred in the mixing zone or from seepage reflux. The result is little cementation and a heterogeneous porosity development. The diagenetic events occurred in the following order: (1) degrading neomorphism and dissolution, (2) first generation (early) dolomitization (finely crystalline), and (3) second generation (late) dolomitization (coarsely crystalline). The basic pore types are secondary moldic, intercrystalline, micro-intercrystalline, and channel pores. The reservoir has good storage flow capacity and is a candidate for CO_2 flooding.

2.3 Heron North Field and Potential Calcarenite Trend

Three generalized regional facies belts, each with unique types of facies, are identified in the Desert Creek zone of the Paradox Formation (figure 2.7): (1) open-marine, (2) shallow-shelf and shelf-margin, and (3) intra-shelf, salinity-restricted facies belts (Chidsey, Eby, and Lorenz, 1996; Chidsey, 1997). All five project fields, as well as the other Desert Creek fields in the region, are located within the shallow-shelf and shelf-margin facies belt. This facies belt includes shallow-shelf carbonate buildups, platform-margin calcarenites, and platform-interior carbonate muds and sands.

The platform-margin calcarenite facies are located along the margins of the larger shallow shelf or the rims of phylloid-algal buildup complexes. Mapping indicates a relatively untested belt of shallow-shelf, calcarenite carbonate deposits (figure 2.7). This narrow but long belt of calcarenite lithofacies is between open-marine lithofacies and the margins of intra-shelf, salinity-restricted lithofacies. Calcarenite buildups represent high-energy environments where shoals and/or islands developed as a result of regularly agitated, shallow-marine processes on the shelf (figure 2.8). Characteristic features of this lithofacies include medium-scale cross bedding, bar-type carbonate

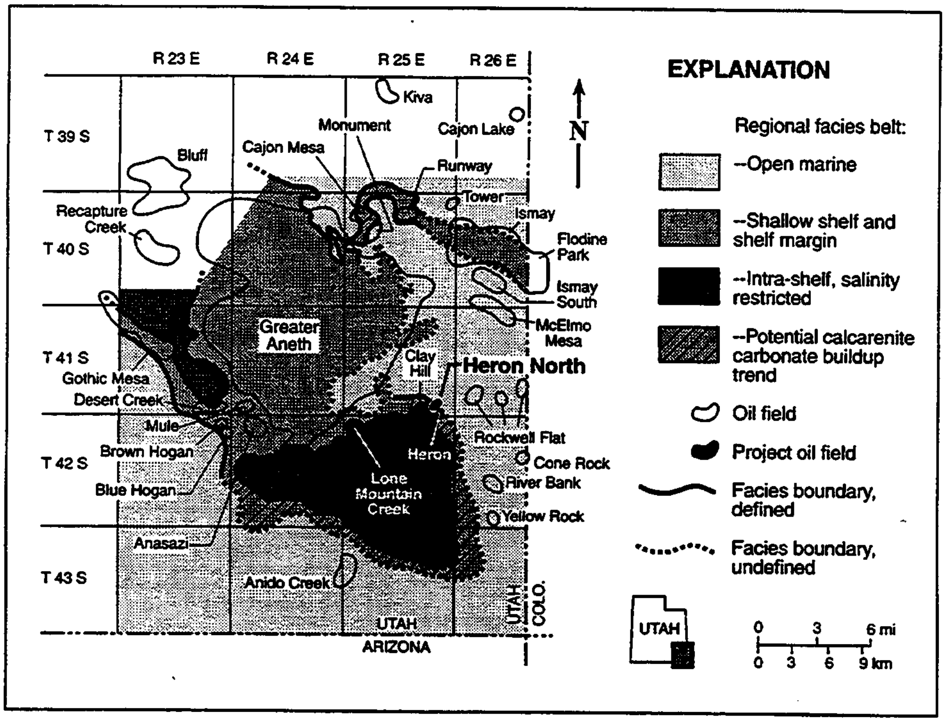


Figure 2.7. Regional facies belts of the Desert Creek zone, Paradox Formation, and potential calcarenite buildup trend, Navajo Nation, southeastern Utah.

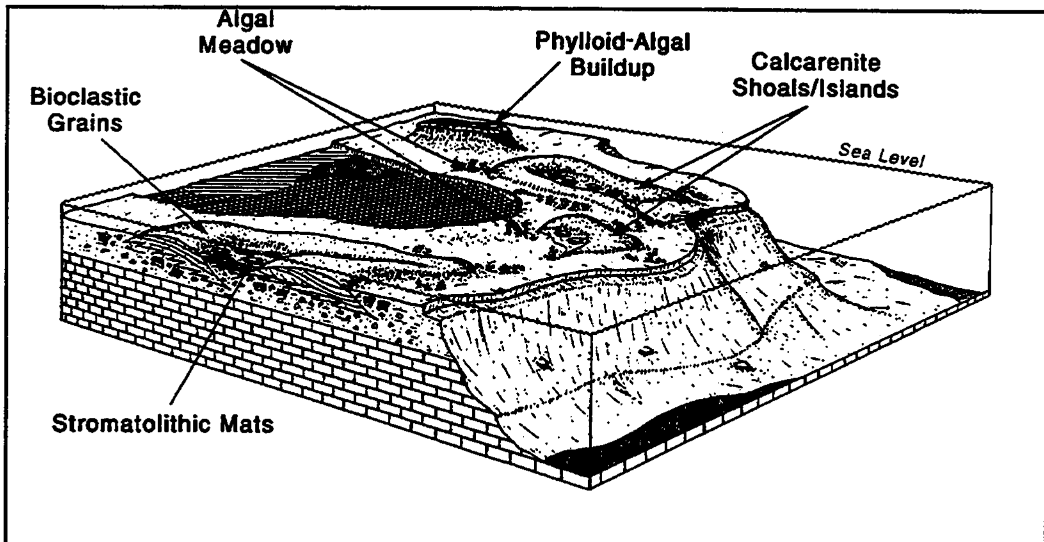


Figure 2.8. Depositional environments of the calcarenite facies along the narrow shelf margin between the open-marine and intra-shelf, salinity-restricted facies belts.

sand-body morphologies, and algal meadows. Stabilized calcarenites occasionally developed subaerial features such as beach rock, hard grounds, and soil zones. Sediment deposition and modification probably occurred from 5 feet (1.5 m) above mean sea level to 20 feet (6 m) below sea level (Chidsey, Eby, and Lorenz, 1996; Chidsey, 1997).

The depositional fabrics of the calcarenite facies include grainstone and packstone. Rocks representing this facies typically contain the following diagnostic constituents: coated grains, hard pelloids, bioclastic grains, shell lags, and intraclasts.

Heron North field (figure 1.1), is an excellent example of the type of fields which potentially lie within this 20-mile-(32-km-)long lithofacies belt. The field consists of one well, the North Heron No. 35-C, completed in 1991 at an initial potential flow (IPF) of 605 barrels (bbls) of oil per day (BOPD [96 m^3/d]) and 230 thousand cubic feet of gas per day (MCFGPD [6,514 m^3/d]). The field is a lenticular, northwest- to southeast-trending linear mound/beach complex, 0.8 miles (1.3 km) long and 0.5 miles (0.8 km) wide (Chidsey and others, 1996a). The reservoir consists of five units (figure 2.3): (1) a basal, dolomitized phylloid algal (bafflestone) buildup, (2) a limestone, anhydrite-plugged phylloid algal (bafflestone) buildup, (3) a fusilinid-bearing, lime-wackestone interval, (4) a dolomitized packstone interval with anhydrite nodules, and (5) a porous (15 percent), sucrosic, dolomitized grainstone and packstone interval, the main reservoir, consisting of alternating 2- to 4-(0.6-1.2-m) ft-thick packages of uniform beach calcarenite and poorly sorted foreshore and storm-lag rudstone or breccia deposits.

Cumulative production from Heron North field is 206,446 bbls of oil (BO [32,825 m^3]) and 0.33 billion cubic feet of gas (BCFG [0.01 billion m^3]) as of July 1, 1997 (Utah Division of Oil, Gas and Mining, 1997). Estimated primary recovery from the field and others that are likely along the trend is 990,000 BO (157,410 m^3) and 2.65 BCFG (0.08 billion m^3). These types of traps have both negative and positive characteristics for hydrocarbon production. Negative characteristics include: (1) small reservoir size and storage capacity, (2) difficult to identify on seismic records, (3) limited distribution, (4) bitumen plugging is common, and (5) rapid production declines. Positive characteristics include: (1) excellent overall reservoir properties, (2) associated with phylloid-algal buildups representing additional drilling targets, (3) candidates for water/CO_2 floods, and (4) located on an extensive untested trend (Chidsey and Eby, 1997).

2.4 Mule Field: Horizontal Drilling and Completion Program

Mule field was identified as a seismic anomaly in the Desert Creek zone of the Paradox Formation near the southwestern edge of the Greater Aneth field (figure 1.1). The field consists of two wells, the Mule No. 31-K-1 (N) discovery well and the Mule No. 31-M well. Mule field is a mud-free, phylloid-algal buildup combined with mound-flank detrital deposits (Chidsey and others, 1996b; Chidsey, Eby, and Lorenz, 1996). The Mule No. 31-K-1 (N) well was deviated about 1,140 feet (347 m) south-southeast, avoiding topographic problems and a highway, to encounter what was thought to be the main part of the buildup (figure 2.9). Several beds in the well core exhibit characteristics of mound-flank deposits such as down slope gravity transport and sharp erosional basal contacts. The Desert Creek zone tested approximately 10 bbls (1.6 m^3) of oil per hour (based on several swab tests) with water cut increasing on each test, and produced only 283 bbls (50 m^3) of oil before the well was shut-in. The Mule No. 31-M offset well encountered a thick mound-core

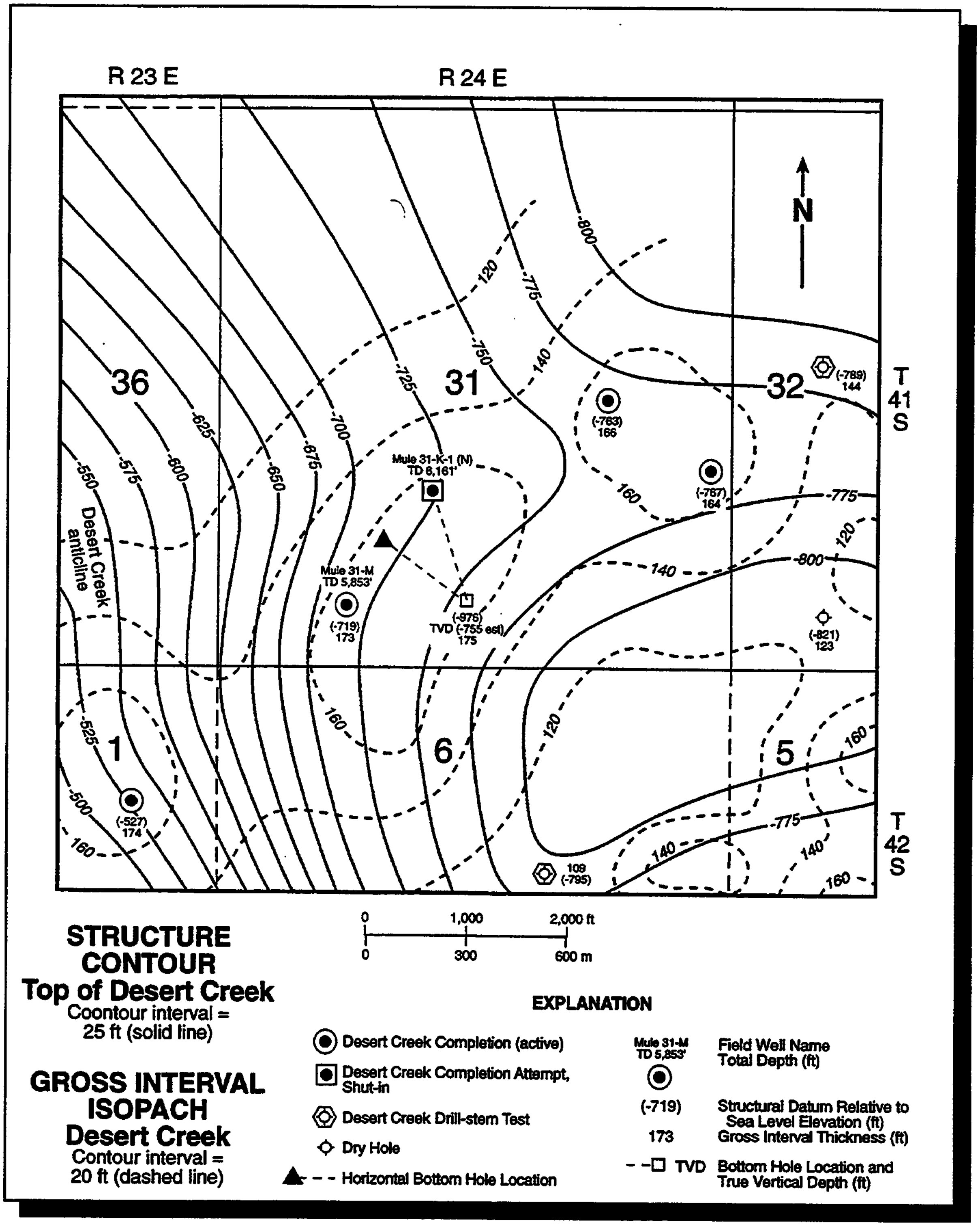


Figure 2.9. Combined Desert Creek zone structure contour and gross interval isopach map, Mule field, San Juan County, Utah (from Chidsey and others, 1996b).

interval and had an IPF of 735 BOPD (117 m^3/d) and 97 MCFGPD (2,747 m^3/d) from the Desert Creek zone.

Isochron maps, based on new seismic data (Chidsey, 1997), indicated Mule field is a lenticular, north to northeast-trending, linear mound with additional reservoir potential on strike to the northeast of the Mule No. 31-M well (figure 2.9). Harken Southwest Corporation, the field operator, determined the most economical way to penetrate a significant portion of this potential mound buildup was to re-enter the Mule No. 31-K-1 (N) well and drill horizontally in a northwest direction.

2.4.1 Horizontal Sidetrack

The Mule No. 31 K-1 sidetrack was the first horizontal test of a small algal buildup in the Paradox basin (figure 2.10). The sidetrack began at a measured depth of 6,029 feet (1,838 m) and drilled to a measured depth of 7,044 feet (2,147 m) (5,807 feet [1,770 m] true vertical depth) with a horizontal displacement of 939 feet (286 m). Well cuttings and the mud log (no geophysical logs were run) indicate the following:

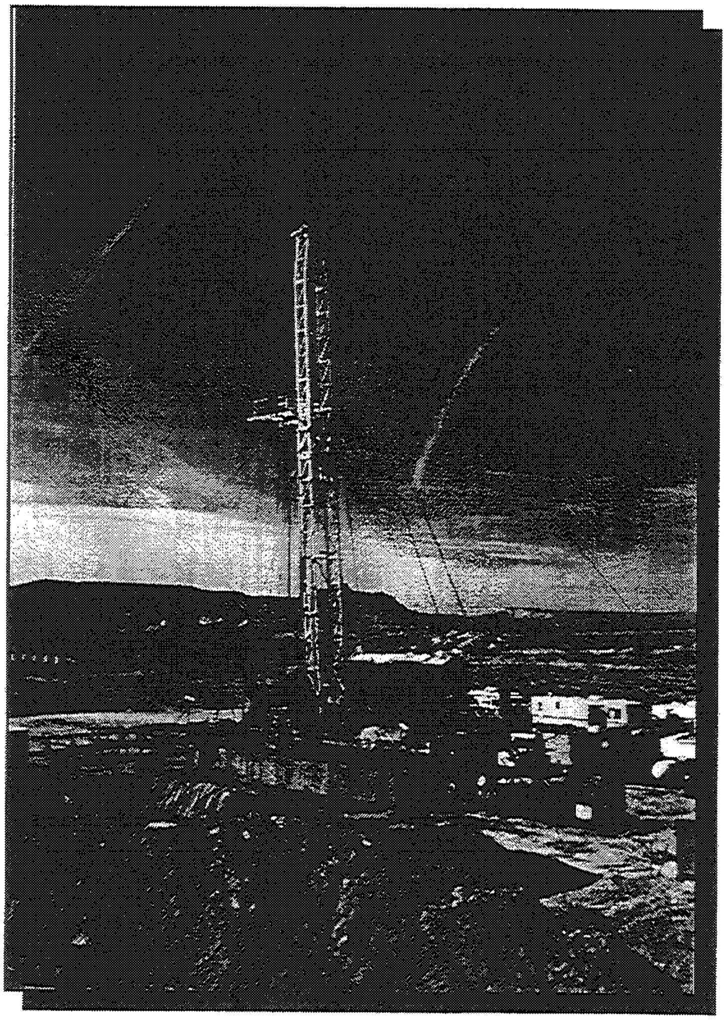


Figure 2.10. Drilling operations for the Mule 31-K-1 horizontal sidetrack well, Navajo Nation, San Juan County, Utah. Photo by R.L. Bon, UGS.

(1) Forty-five vertical feet (14 m) of anhydrite was encountered at the top of the Desert Creek zone or above the supra-mound interval of the buildup facies. This compares to 25 feet (7.6 m) of anhydrite in the Mule No. 31-M well.

(2) The horizontal sidetrack encountered a supra-mound interval 21 vertical feet (6.4 m) thick consisting of very finely crystalline to micro-sucrosic dolomite and thin interbedded limestone. At a measured depth of 6,000 feet (1,829 m), 38 vertical feet (11.6 m) of algal grainstones were penetrated in what was expected to be the mound-core interval. These rocks may represent overwash

deposits into a lagoon associated with the algal buildup. No algal bafflestones were encountered.

(3) At 6,065 feet (1,849 m) measured depth, tight clay-rich packstone, marlstone, dolomite, and thin carbonaceous shale were encountered over a distance of 329 horizontal feet (100 m). These rocks possibly represent the platform interval, the base upon which algal colonies grew. At a measured depth of 6,171 feet (1,881 m), the drill string was directed upward in an attempt to find the mound-core interval. At a measured depth of 6,395 feet (1,949 m) the lithology changed to a possible mound-front breccia consisting of packstone with algal and grainstone inclusions. The drill string was turned downward at a measured depth of 6,670 feet (2,033 m) and, after penetrating 500 horizontal feet (152 m) of "mound-front facies," the drill string returned to the possible platform interval packstones from a measured depth of 6,900 feet (2,103 m) to the end of the horizontal lateral. An alternate interpretation is that the wellbore only penetrated the supra-mound interval with the mound-core interval below remaining for an additional horizontal test.

The total depth and horizontal length were reached on March 26, 1997. Some zones of intercrystalline porosity in dolomites and black residual oil staining observed in the cuttings lead the operator to attempt a well completion.

2.4.2 Horizontal Completion

The Mule No. 31-K-1 horizontal well was completed open hole following treatment with acid and several swab runs. The following intervals were treated with 15 percent hydrochloric acid (HCl): (1) 6,900 to 6,960 feet (2,103-2,121 m) MD - 1,000 gallon (gal [3,785 L]) HCl, (2) 6,700 to 6,900 feet (2,042-2,103 m) MD - 1,000 gal (3,785 L) HCl, (3) 6,550 to 6,700 feet (1,996-2,042 m) MD - 2,000 gal (7,570 L) HCl, (4) 6,430 to 6,550 feet (1,960-1,996 m) MD - 3,000 gal (11,355 L) HCl, (5) 6,100 to 6,430 feet (1,859-1,960 m) MD - 1,000 gal (3,785 L) HCl, and (6) 5,980 to 6,100 feet (1,823-1,859 m) MD - 2,000 gal (7,570 L) HCl. After swabbing for five days all load water had been recovered with oil recoveries ranging between 4 and 16 percent. Swabbing continued for six more days recovering about 300 bbls (48 m^3) of fluid, containing 10 percent oil.

The well was shut in for two months after which the operator decided to conduct swabbing operations again. The result was much different with recoveries between 40 and 60 percent oil during four days of swabbing. The large amounts of water recovered from the first series of swab runs was apparently water lost during drilling operations. The Mule No. 31-K horizontal well finalized at a rate of 149 bbls (24 m^3) of oil and 223 bbls (35 m^3) of water per day respectively. The first month of production for the well is summarized in figure 2.11.

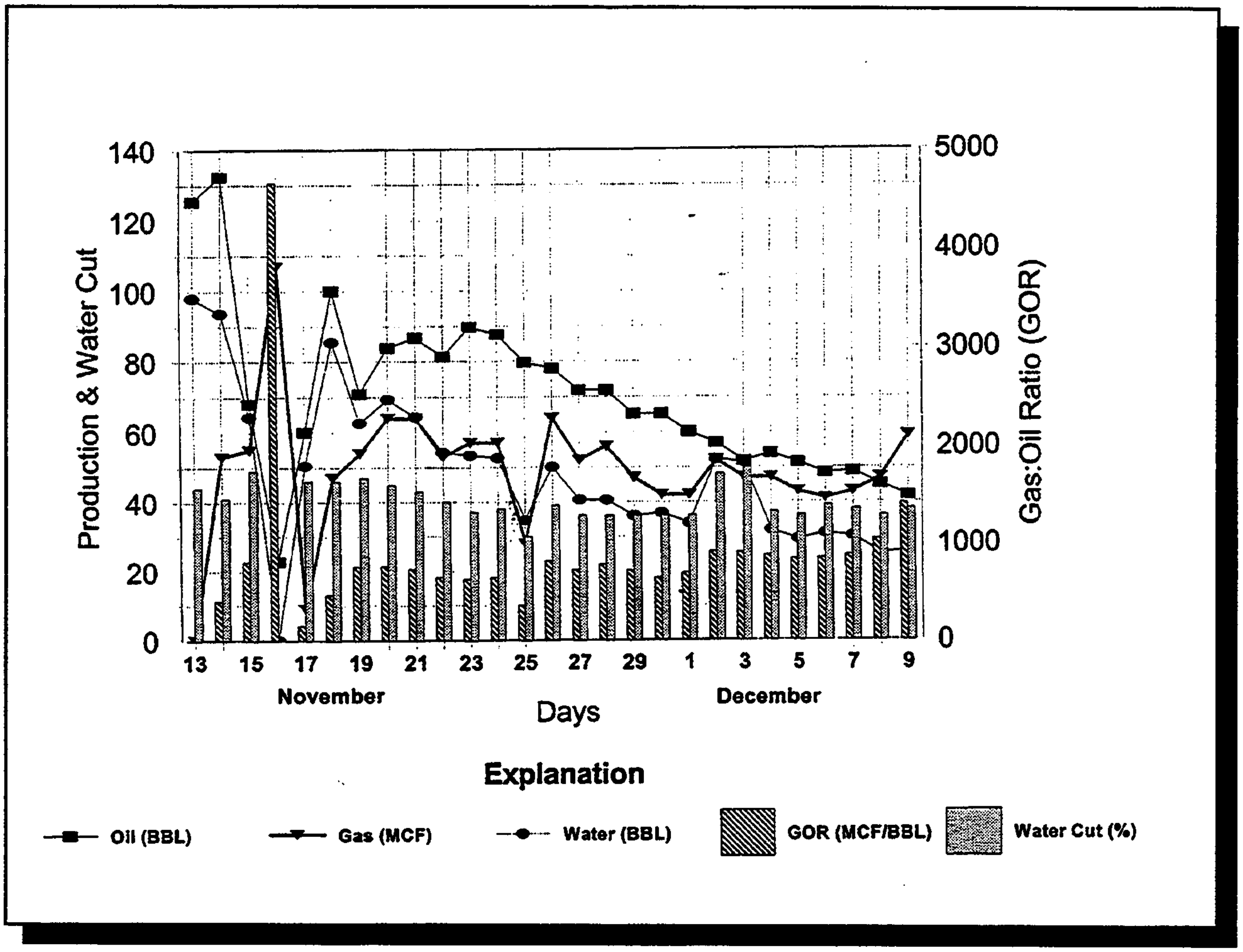


Figure 2.11. First month of production graph for the Mule 31-K-1 horizontal sidetrack well. Production data from Kris Hartmann, Harken Southwest Corporation (written communication, 1997).

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3. GEOSTATISTICAL MODELING AND RESERVOIR SIMULATION: ANASAZI FIELD

Douglas M. Lorenz and William E. Culham; REGA Inc.
and
Thomas C. Chidsey, Jr.; Utah Geological Survey

Of the five carbonate buildup fields in the Desert Creek zone originally identified as candidates for detailed study, the Anasazi field was selected for the initial geostatistical modeling and reservoir simulation (figure 1.1). This mound complex has the longest production history (more than seven years) and largest amount of hard data for reservoir characterization (four logged wells, three of which are also cored through the Desert Creek zone), has the most seismic coverage (six two-dimensional lines), and was considered the most promising candidate for enhanced recovery.

The key to increasing ultimate recovery from the Anasazi field (and similar fields in the basin), is to design either waterflood or CO_2-miscible-flood projects capable of forcing oil from high-storage-capacity but low-recovery supra-mound units into the high-recovery mound-core units. The results of these statistical models are being used in reservoir simulations to test and design those types of projects.

3.1 Anasazi Field Overview - Location, Geometry, and General Stratigraphy

The discovery well for the Anasazi field, the Anasazi No. 1 (SW1/4NW1/4 section 5, T. 42 S., R. 24 E., Salt Lake Base Line), was completed in 1990 at an IPF of 1,705 BOPD (271 m^3/d) and 833 MCFGPD (23,591 m^3/d) from the Desert Creek zone. The Anasazi prospect, located off the southwest edge of the Greater Aneth field, was identified as a seismic anomaly near the east flank of the Desert Creek anticline. Cumulative production from Anasazi field is 1,785,813 BO (283,944 m^3) and 1.47 BCFG (0.4 billion m^3) as of July 1, 1997 (Utah Division of Oil, Gas and Mining, 1997). Estimated primary recovery from the field is 2,069,392 BO (329,033 m^3) and 1.89 BCFG (0.054 billion m^3) (Chidsey and others, 1996).

The detailed combined structure/isopach map of the Desert Creek zone in the Anasazi area (figure 3.1) shows two mound buildups more than 60 feet (18 m) thick, based on well log and seismic information. Three peripheral dry holes (Navajo No. 4-D [section 5, T. 42 S., R. 24 E., Salt Lake Base Line], Navajo No. D-1 [section 6, T. 42 S., R. 24 E., Salt Lake Base Line], and Navajo No. B-7 [section 32, T. 41 S., R. 24 E., Salt Lake Base Line]) do not penetrate any mound buildup facies in the Desert Creek zone, and serve to define the average non-mound Desert Creek thickness (110 feet [34 m]) in the vicinity of the Anasazi field.

Anasazi field is a lenticular, west- to northeast-trending lobate mound, 0.9 miles (1.5 km) long and 2,000 to 3,000 feet (610-914 m) wide (Chidsey and others, 1996). The reservoir consists of a mud-poor, phylloid-algal buildup. A variety of carbonate facies is encountered in all four Anasazi wells which causes a high degree of spatial heterogeneity in reservoir properties. To adequately represent the effects of this heterogeneity on reservoir behavior, detailed characterizations

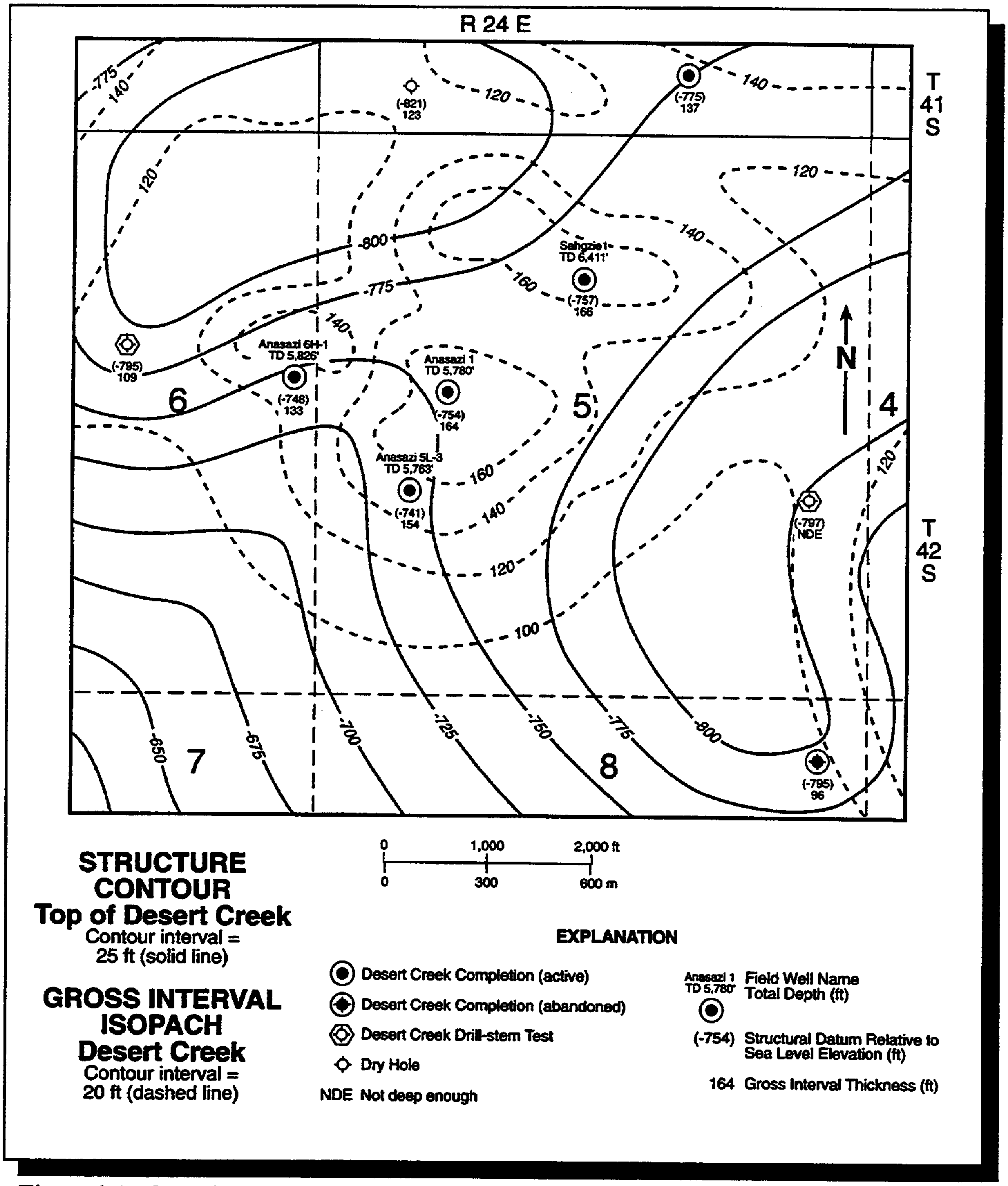

Figure 3.1. Combined Desert Creek zone structure contour and gross interval isopach map, Anasazi field, San Juan Co. Utah (Chidsey and others, 1996).

of these heterogeneous facies and their joint distributions within the reservoir volume must be developed.

In the mound buildup area, the Desert Creek zone is stratigraphically subdivided into three intervals. The lowest interval, averaging 25 feet (8 m) in thickness, consists largely of tight dolomudstones, with some slightly enhanced porosity (up to 10 percent) and interbedded dolomitized packstones and wackestones. A middle interval or mound core (30 to 50 feet [9-15 m] thick) is comprised almost entirely of phylloid-algal bafflestone. These mound-building limestones exhibit substantial porosity (up to 22 percent locally) and permeability (generally 150 to 300 millidarcies [md]; locally greater than 1,000 md). Thin dolomudstones, packstones, wackestones, and a few grainstones are found in flanking peripheral areas. The upper interval (55 to 65 feet [17-20 m] thick) contains mostly dolomitized mudstones, packstones, wackestones, and grainstones in which each lithotype shows a wide range of secondary pore system alteration from slight (porosity less than 2 percent and permeability less than 0.1 md) to significant (porosity greater than 24 percent and permeability up to 50 md). Based on detailed core and log interpretations of the Anasazi wells and on geological studies of nearby analogous Pennsylvanian carbonate mound buildups (Chidsey, Brinton, Eby, and Hartmann, 1996; Chidsey, 1997), these three successive stratigraphic intervals are identified as distinct time-equivalent sequences, termed the "platform interval", the "mound-core interval" and the "supra-mound interval", respectively. Detailed correlation of flooding surfaces demonstrates their lateral continuity within the Anasazi mound complex. The mound-core and supra-mound intervals together constitute the Anasazi reservoir; the platform interval is tight and does not yield commercial hydrocarbons.

To represent the vertical and lateral heterogeneity known to be present in the Anasazi reservoir, yet ensure that the well-documented lateral and vertical communication also is realistically modeled, a detailed facies interpretation of the conventional core from three Anasazi wells (Anasazi Nos. 1, 5L-3, and 6H-1) was undertaken during the first year of the project. From these results, together with the log interpretations, conventional core analysis, and geologically inferred lateral facies relationships based on the outcrop studies, a reservoir modeling procedure was designed to incorporate the major facies types as individual architectural entities, each exhibiting internal heterogeneities in reservoir properties but contrasting sharply between the individual lithotypes. All ten architecturally distinct lithotypes were identified in the mound core interval, eight of which also comprise the supra-mound interval in the Anasazi reservoir (Chidsey, Eby, and Lorenz, 1996; Chidsey, 1997a). They include the tight mudstones, packstones, wackestones, and grainstones characteristic of the off-mound areas in both intervals; similar facies exhibiting enhanced porosity resulting from dolomitization and/or leaching found in the buildup areas of the supra-mound interval (and also scattered throughout off-mound areas; and the porous, highly permeable phylloid-algal bafflestones and associated mound-flank breccias which are almost entirely restricted to the buildup areas of the mound-core interval.

3.2 Reservoir Geostatistical Modeling

The significant heterogeneity in by both the lithotypes and the reservoir properties at Anasazi field requires development of a multi-stage procedure for incorporating the variation known to exist in conventional cores from Anasazi field and outcrop analogues into the reservoir geostatistical model.

3.2.1 Architectural Modeling

The internal architecture of the reservoir between the wells was modeled using a marked point (Boolean) process for emplacement of the 10 constituent lithotypes. This process was constrained by both the relative volumetric percentages of the various lithotypes observed in the wells and outcrops, and the average porosity map obtained from seismic interpretation. Simple rectangular geometries sufficed to represent the individual lithotype bodies, dimensions for which were described by triangular probability distributions. Fifteen geostatistical layers, each consisting of a 30 by 50 block grid (1,500 blocks per layer or a total of 22,500 blocks for the 15 layers), were used for reservoir modeling and flow simulation. Each grid block measures 105 feet square (32 m^2) and varies between 3.5 and 7 feet (1-2 m) in thickness. Emplacement sequences were established (for example cementation/dissolution following emplacement of the unaltered lithotype) and the relative lithotype proportions varied stochastically.

3.2.2 Porosity Modeling

The pair-wise block-exchange process for simulating reservoir porosity between the Anasazi wells was carried out using a stochastic relaxation technique known as "simulated annealing." The method postulates an objective function computed from the model data prior to each proposed block exchange. This function is compared with a target value to determine whether the exchange would result in a closer match. If so, the exchange is made and the objective function updated. Even if the match would deteriorate slightly, the exchange can be accepted with a (specified) finite probability. As the process proceeds, this probability of accepting a slightly degraded porosity model declines.

The objective function for fitting the Anasazi reservoir porosity model consists of the sum of two weighted components: (1) local spatial variation, and (2) global average reservoir porosity, estimated from the seismic reservoir-quality index (Chidsey, 1997b). Local spatial variation of porosity was measured by horizontal and vertical variogram models based on data from analogous carbonate mound outcrops in the Ismay zone of the Paradox Formation along the San Juan River, Utah and the four Anasazi wells (Chidsey, Eby, and Lorenz, 1996; Chidsey and others, 1996).

Porosity was initially assigned randomly to each gridblock, the value selected from a probability distribution developed for each lithotype based on log, core, and outcrop data. Fitting to the variograms and average porosity constraints was achieved by block exchange, moderated by imposed requirements for maintaining architectural continuity of the previously emplaced lithotype bodies. Although the sizes, shapes, and geometric configurations of the individual architectural bodies were allowed to change, the total number of contiguous bodies was not. Thus, although the detailed geometries of the original simple lithotype units changed dramatically, the overall statistical properties of lithotype distribution were retained.

Several features of the geostatistical models are noteworthy. First, the mound-core and supra-mound intervals are clearly distinguished by the continuous development of the highly permeable phylloid algal limestone in the mound-core interval, contrasted with the heterogeneous, less permeable but more porous mixed lithotypes draped over the core in the supra-mound interval. Second, much of the off-mound area is occupied by the three types of carbonate mudstone, while most of the supra-mound interval directly above the mound core consists of non-mud lithotypes. This is in keeping with lithotype distributions in the Anasazi wells and in the lower Ismay outcrops. Finally, although much of the inter-mound area contains either fine-grained, tight mudrocks or cemented skeletal grainstones, several layers of more porous and permeable grainstones or enhanced porosity lithotypes extend between the mound areas, both in the mound-core and supra-mound intervals. These "sheets" of better quality reservoir rock provide the communication between the mound buildup areas required to allow the equalization of reservoir pressure observed during field development.

3.2.3 Fifteen-Layer Simulation Model

Sensitivity studies were conducted which indicated that most of the variation in effective reservoir properties could be retained with careful scaling of porosity and permeability. Lithotypes were assigned to each of the 15-layer gridblocks according the dominant lithotype. Where no single lithotype predominated, the block was assigned to one of two new lithotype categories termed "poor quality" and "good quality" mixed lithologies. Porosity was volume-averaged for the 15-layer model, and effective permeability was computed by solution of the pressure equation using a field-scale reservoir simulator. Distribution of lithotypes, porosity, and permeability for a typical realization of the final 15-layer model are illustrated in the block diagrams (figures 3.2 through 3.4). Two modeled injector wells and the three producing wells (Anasazi No. 1, Anasazi No. 5L-3, and Sahgzie No. 1) are also shown.

3.3 Reservoir Simulation

The reservoir analysis for the Anasazi field required a field-scale reservoir simulator. Enhanced recovery through CO_2-flooding and water-flooding were evaluated using a compositional simulation. Variations in carbonate lithotypes, porosity, and permeability were incorporated into the simulation in order to accurately predict reservoir response (Chidsey, 1997a; Lorenz and others, 1997). History matches were made by tying to previous production and reservoir pressure history so that future reservoir performance could be confidently predicted.

3.3.1 Reservoir Performance Prediction Studies Using CO_2 Injection

Compositional simulation was used to history match the past production performance of the Anasazi field and predict the performance of continued primary depletion and various CO_2 floods. The simulation study employed a stochastically generated reservoir description employing 12 different facies. The reservoir fluid was characterized via a 11-pseudo-component equation of state calibrated using CO_2-swelling tests conducted on Anasazi crude oil and the original black oil pressure-volume-temperature (PVT) data. The past production performance was history matched using production history data from the wells in the field. Key history match variables included individual well and field gas production rates, and periodically measured reservoir pressure values.

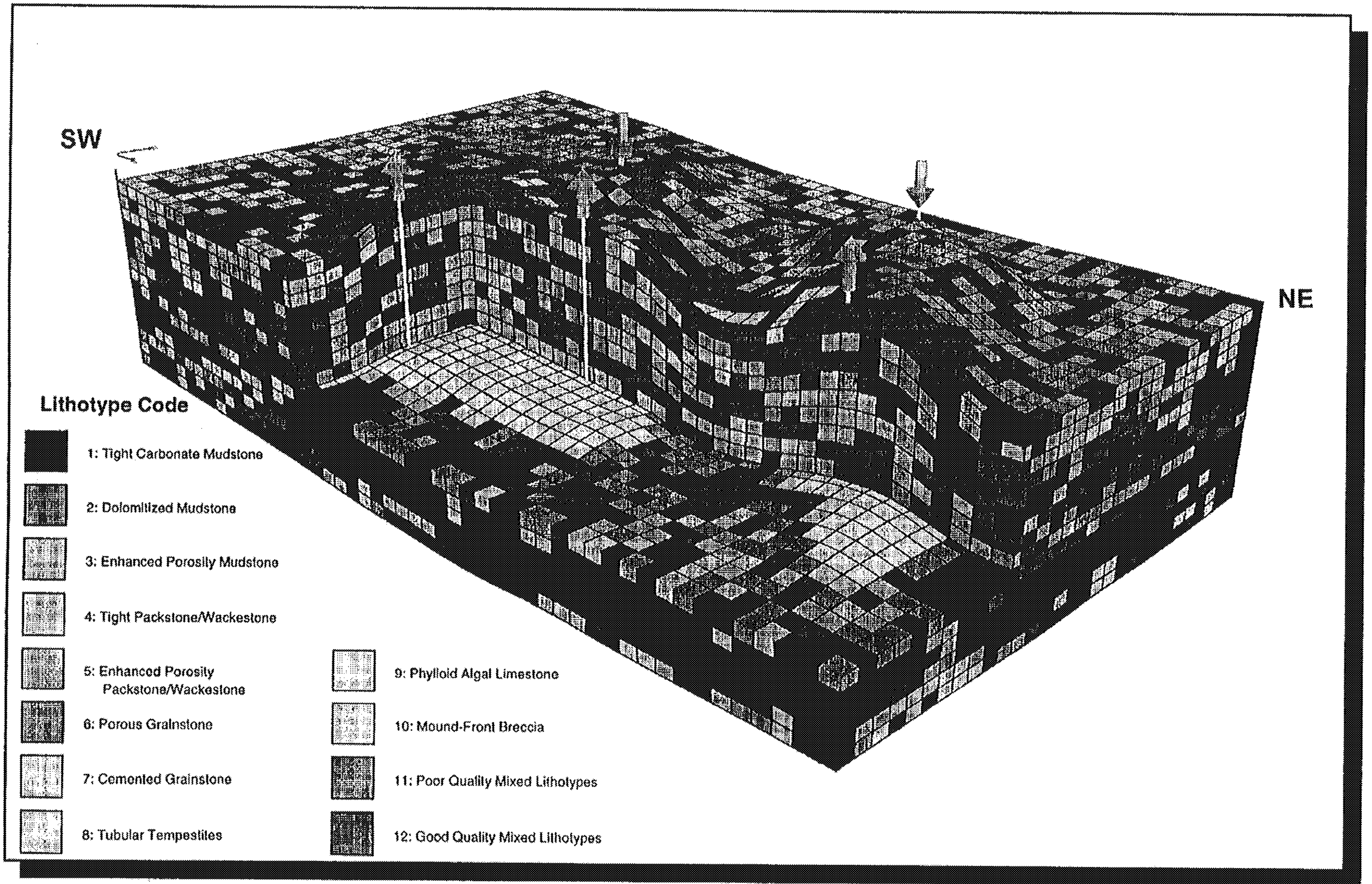

Figure 3.2. Block diagram displaying distribution of lithotypes in the 15-layer reservoir simulation model, Anasazi field. Arrows directed up are producing oil wells, arrows directed down are CO_2 injectors. The layers consist of a 30 by 50 block grid (1,500 blocks per layer or a total of 22,500 blocks for the 15 layers). Each grid block measures 105 feet square and varies between 3.5 and 7 feet in thickness. The layer at the bottom of the "cut away" is the boundary between mound-core and supra-mound intervals.

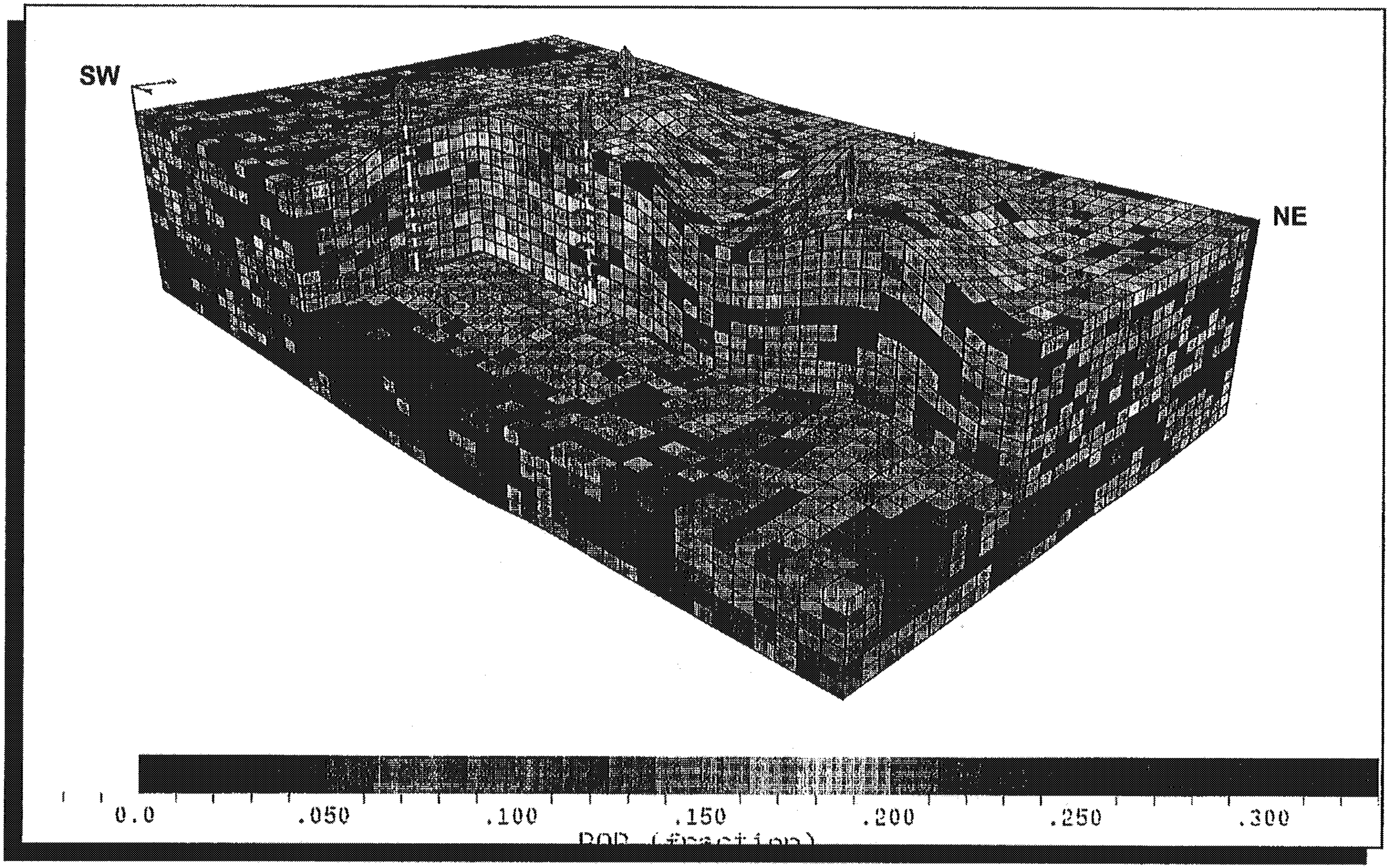

Figure 3.3. Block diagram displaying distribution of porosity (fraction) in the 15-layer reservoir simulation model, Anasazi field.

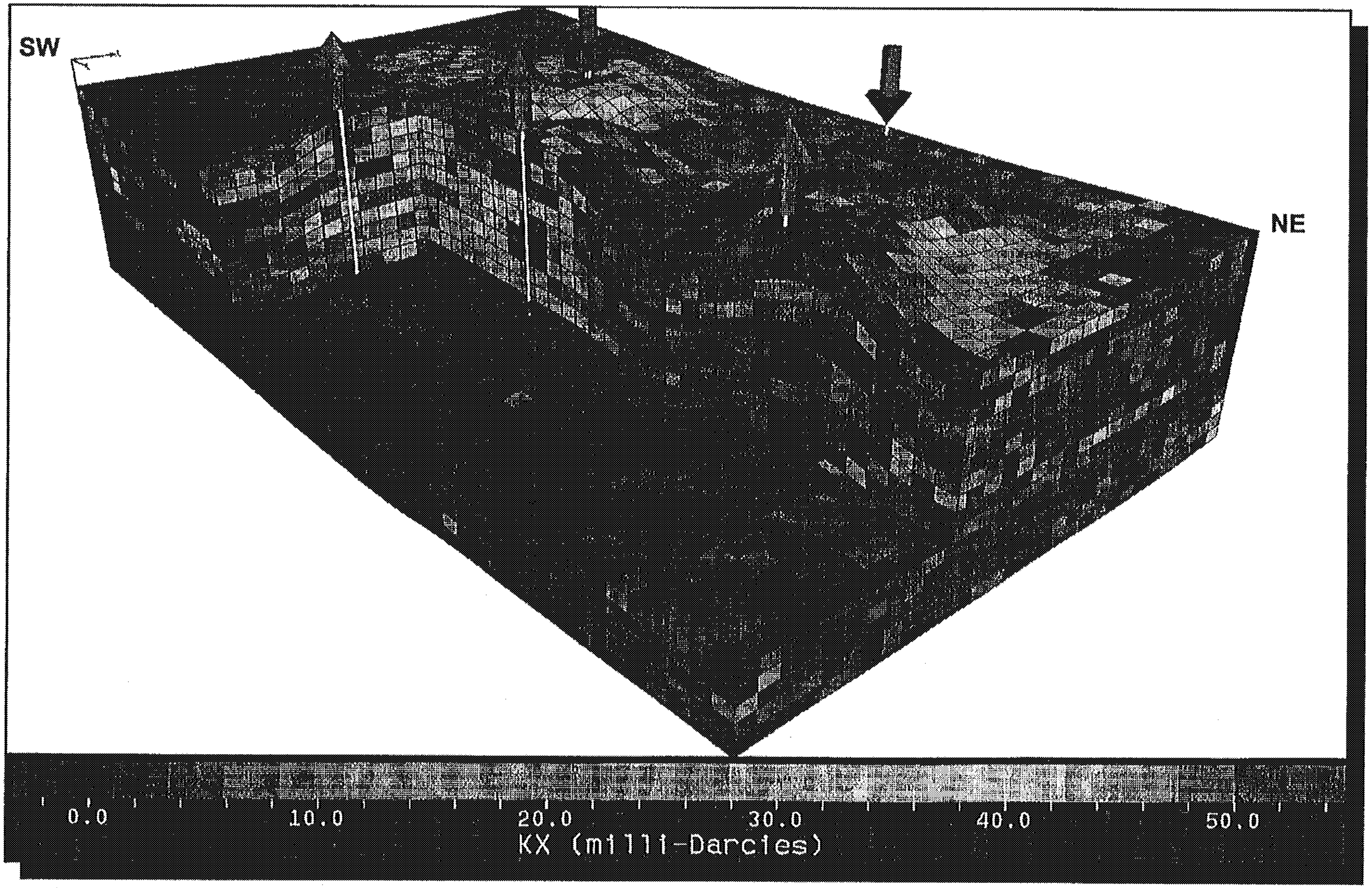

Figure 3.4. Block diagram displaying distribution of permeability (md) in the 15-layer reservoir simulation model, Anasazi field.

Once the simulator was calibrated, by obtaining a suitable match of production data, it was used to predict the performance of the reservoir under continued primary production and CO_2-flood operations.

Various CO_2-flood operating conditions, injection well placement, and configurations were investigated. Carbon dioxide-flood performance predictions for several different operating conditions and well configurations have been completed. Figure 3.5 compares primary depletion performance versus CO_2 flooding. For this example the incremental oil recovery over primary production at January 1, 2011 is about 2.0 million stock tank barrels (MMSTB [318,000 m^3]). Figure 3.6 illustrates the predicted oil saturation at the start of CO_2 injection. Six years of primary production has generated a variable free-gas saturation (0 to 40 percent) as well as producing 1.75 MMSTB (278,250 m^3) of oil. The simulator predicts extensive gas segregation into the supra-mound interval.

The oil saturation after 10 years of CO_2 injection in two injectors, one located in the southwest lobe and the other in the northeast lobe of the buildup, is shown in figure 3.7. The figure illustrates two important points: (1) reservoir pressurization redissolves all the free hydrocarbon gas present at the start of injection, returning the majority of the reservoir to initial oil saturation values, and (2) the volume of the reservoir contacted by the injected CO_2 shows a near zero residual oil saturation. This displaced oil is produced via existing producers. Both the supra-mound and mound-core intervals have been swept by CO_2. The liquid phase, mole fraction of CO_2 indicates extensive contact of reservoir volume by CO_2. At the operating pressure level of 2,000 to 3,000 pounds per square inch (psi [13,790-20,685 Kpa]), CO_2 and hydrocarbons are at or near miscible conditions. Thus, the oil displacement will be essentially complete (low residual oil saturation values).

Upon completion of the history match of the primary production phase of the Anasazi field a series of CO_2 -flood cases were completed. This series of cases accomplished the following:

- Identified CO_2 flood operating pressure to obtain process miscibility.
- Identified the optimum location for two CO_2 injectors based on the current reservoir description.
- Quantified the reservoir performance and economic impact of removing hydrocarbon gases from the produced gas stream and re-injection of CO_2 versus re-injection of unprocessed produced gas (CO_2 plus hydrocarbon components).
- Evaluated the use of horizontal injection wells versus vertical injectors.
- Quantified the performance of a process combining CO_2 injection followed by reservoir blow down.

Figure 3.8 compares oil recovery between continued primary production and continuous CO_2 injection through the year 2012. The incremental oil recovery for the CO_2 flood versus primary production is approximately 2.5 MMSTB (397,500 m^3) of oil. Recovery of this additional oil required purchase of 12.0 BCF (0.34 billion m^3) of CO_2 plus injection of produced gas.

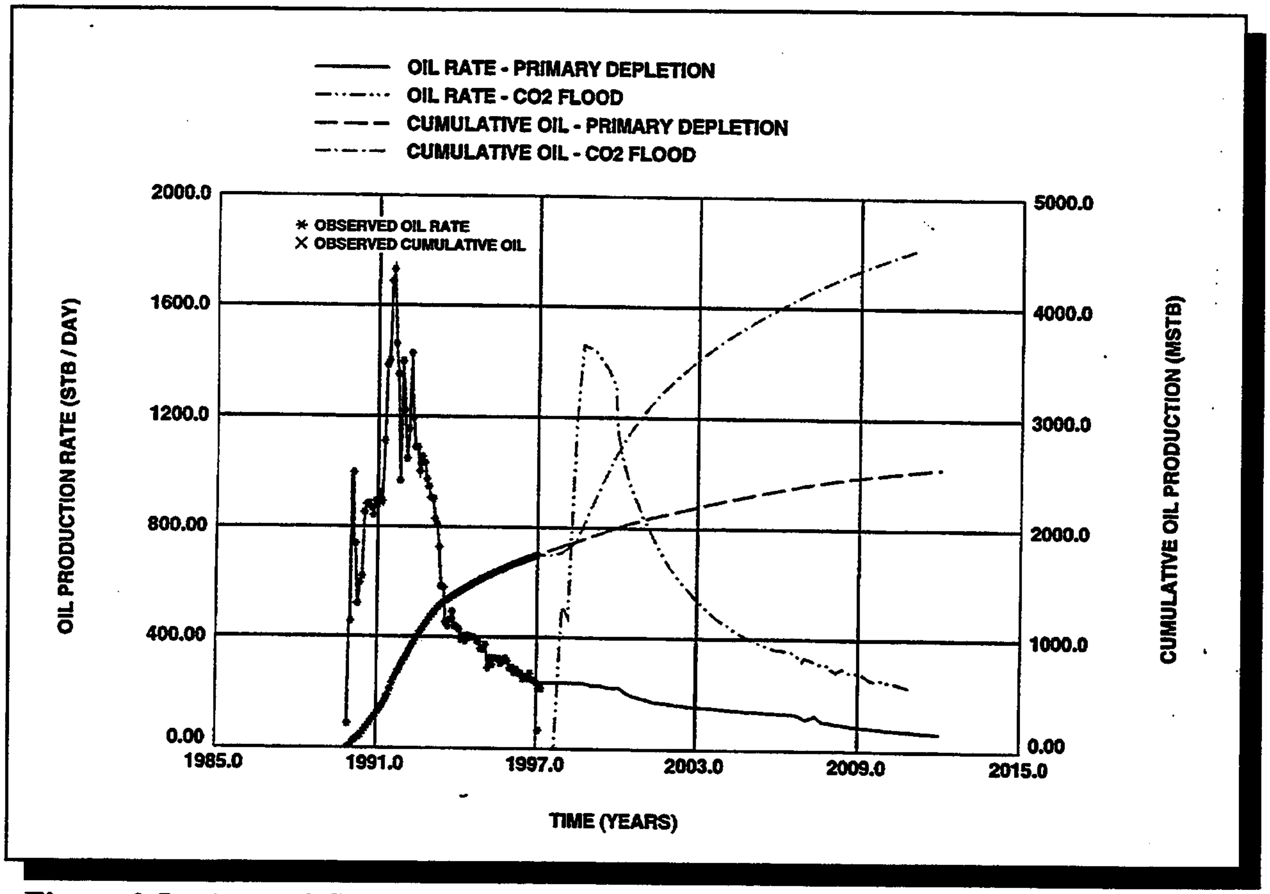

Figure 3.5. Anasazi field oil-production rate and cumulative oil production comparing primary depletion and CO_2 flooding vs. time.

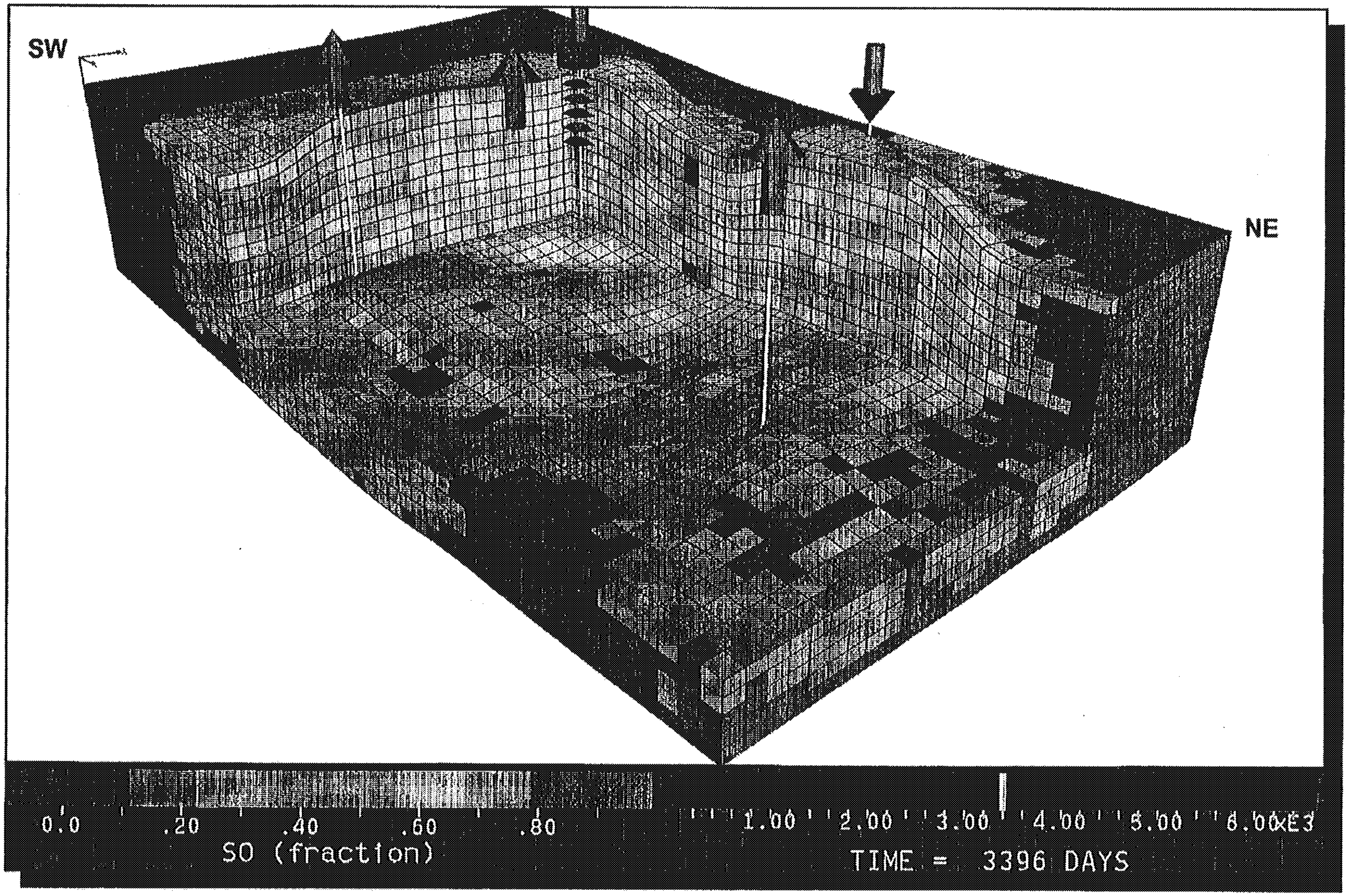

Figure 3.6. Block diagram displaying reservoir oil saturation at the start of CO_2 injection (January 1, 1997). Shown is a "cut away" through one of the proposed CO_2 injectors at the Anasazi No. 6H-1 well location and the Anasazi No. 5L-3 well location.

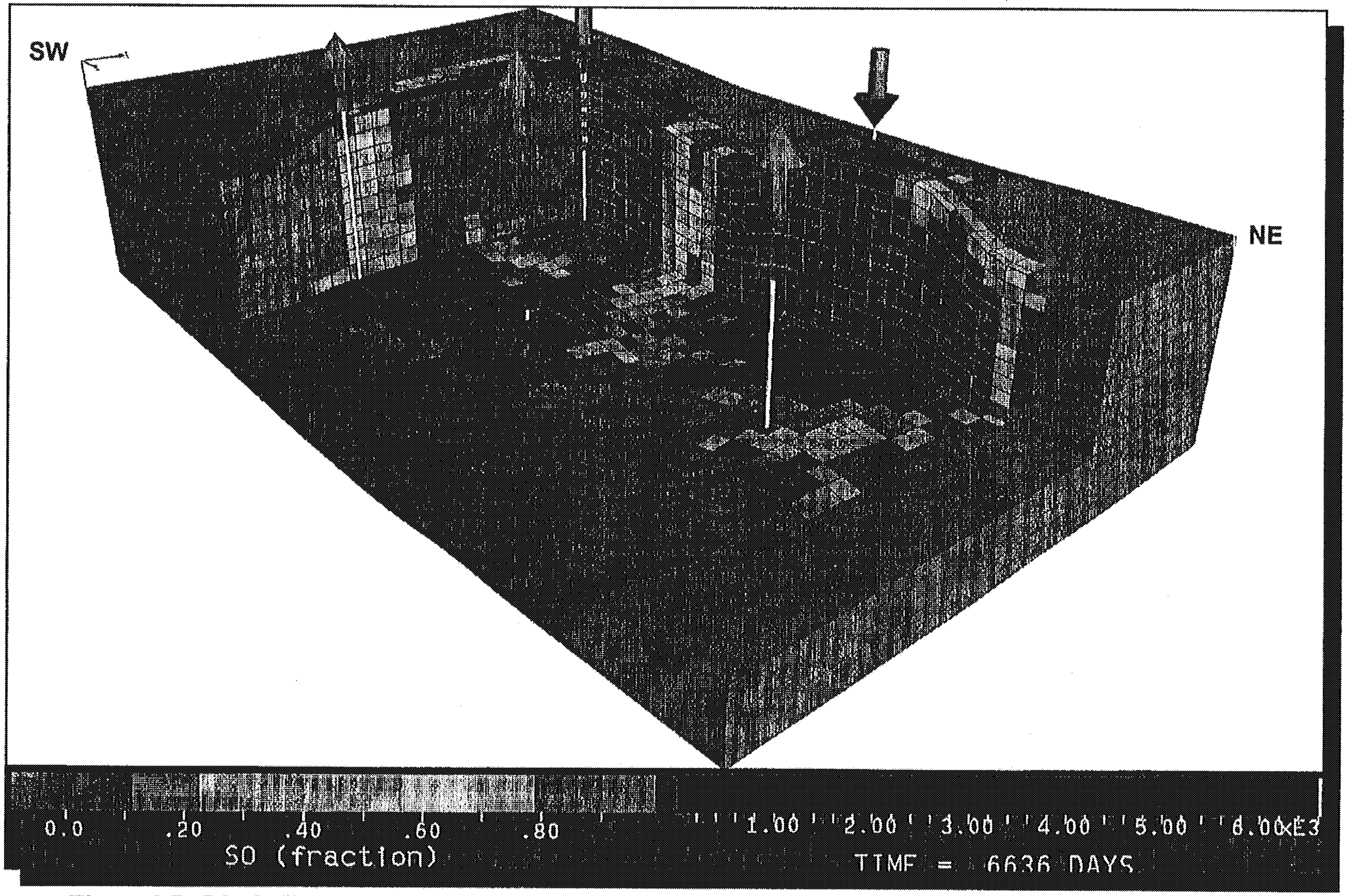

Figure 3.7. Block diagram displaying reservoir oil saturation after 10 years of CO_2 injection (January 1, 2008).

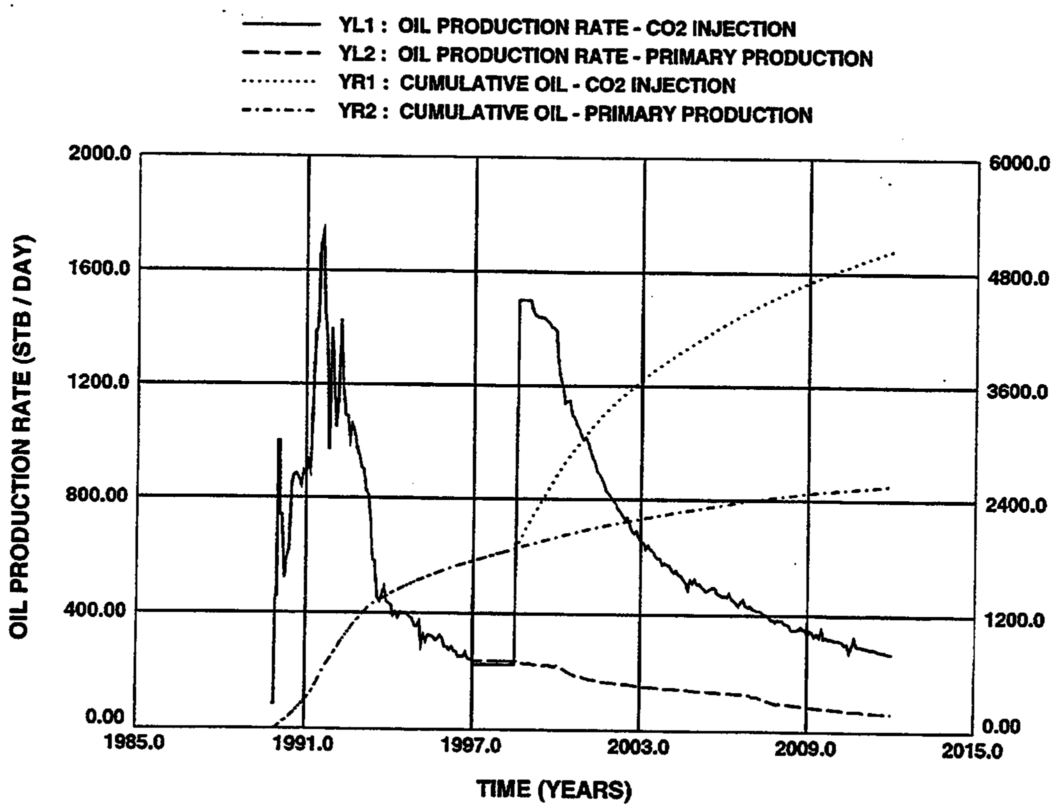

Figure 3.8. Oil recovery - primary versus continuous CO_2 injection, Anasazi field.

Two final simulation prediction cases (A and B) were to serve as the basis for the economic assessment of CO_2 flooding. The principal operating parameters and simulation related data in effect for these simulation cases were:

- CO_2 injection starts on January 1, 2000.

- Simulation case A uses an injection rate of 2.0 million standard cubic feet of gas per day (MMSCFGPD [56,640 m^3/d])/well and case B uses an injection rate of 4.0

MMSCFGPD (113,280 m^3/d)/well. Injection was simulated through one well in each of the two mound lobes (figure 3.1).

- Production wells Anasazi No. 1, Anasazi No. 5L-3, and Sahgzie No. 1 (figure 3.1) were allowed to produce at the rate in effect on January 1, 2000 during reservoir fill-up.

- Produced gas was recycled to reduce CO_2 make-up gas purchases. Thus, no conditioning was employed.

- CO_2 injection was continuous from the start of injection until January 1, 2012.

Table 3.1 summarizes relevant production/injection data for simulation prediction cases A and B. The data shows that for case A, the incremental oil recovery above primary was 951,000 bbls (151,209 m^3) at January 1, 2012. This required injection of 17.5 billion standard cubic feet (BSCF [0.5 billion m^3]) of CO_2 and produced gas and purchase of 10.1 BSCF (0.29 billion m^3) of CO_2. Simulation prediction results indicate that a CO_2 injection rate of 2.0 MMSCFGPD (56,640 m^3/d)/well would not be sufficient to meet ongoing production needs of the operator (Harken Southwest Corporation) and generate acceptable economic returns. It would however, increase recovery by close to 1.0 MMSTB (159,000 m^3) of oil over predicted primary recovery at January 1, 2012.

Table 3.1. Production/injection data for CO_2 flood, Anasazi field.

Case	Cum Oil (MSTB)	Cum Gas (BSCF)	Incremental over Primary (MSTB)	Total Gas Inj. (BSCF)	Total CO_2 Purchase (BSCF)	Total Gas Recycled (BSCF)
Production / Injection at January 1, 2003						
A	2116	1.7	-78	4.4	4.2	0.2
B	2293	2.6	99	8.8	7.8	1.0
Production / Injection at January 1, 2006						
A	2385	2.4	-7	8.8	8.0	0.8
B	3302	9.4	910	17.5	9.8	7.7
Production / Injection at January 1, 2012						
A	3505	9.1	951	17.5	10.1	7.4
B	4208	25.2	1654	35.0	11.5	23.5

The data shows that for case B, the incremental oil recovery above primary was 1,654,000 bbls (262,986 m^3) at January 1, 2012. This required injection of 35.0 BSCF (1.0 billion m^3) of CO_2 and produced gas, and purchase of 11.5 BSCF (0.33 billion m^3) of CO_2. Specifically, using a 4.0 MMSCFGPD (113,280 m^3/d)/well injection rate from two injectors, the CO_2 flood will recovery 4.21 MMSTB (669,390 m^3). This represents an increase of 1.65 MMSTB (262,350 m^3) over predicted primary recovery at January 1, 2012. The projected 4.21 MMSTB (669,390 m^3) represents more than 89 percent of the oil in the mound complex and 36.8 percent of the original oil in place in the total system modeled.

3.3.2 Reservoir Performance Prediction Studies Using Water Injection

The series of waterflood predictions assessed the placement and completion configuration of injection wells and the use of horizontal injector wells versus vertical injector wells.

In general, injection of water had a detrimental effect on continued production during reservoir fill up. Waterfloods recovered less oil than primary production through the year 2012. If waterflood operations were carried out past the year 2012 oil recovery could exceed primary, but ultimate recovery was significantly less than with CO_2 flooding, with the additional expense of operating a waterflood for an extra10 years past the year 2012. Figure 3.9 illustrates one of the waterflood prediction cases versus primary production. At the year 2008 (after 12 years of water injection) oil recovery was approximately 270,000 stock tank barrels (STB [42,930 m^3]) less than primary. At the year 2012 waterflooding still had recovered less than primary (20,000 STB [3,180 m^3]) and approximately 2.5 MMSTB (397,500 m^3) less than CO_2 flooding. The poor performance of waterflooding is attributable to the low injectivity of water and the interference with oil migration into the mound-core interval from the supra-mound interval from both the mound and off-mound areas.

3.3.3 Economic Assessment of the Potential of CO_2 Flooding

Economic assessments were conducted for CO_2 flooding in Anasazi field (waterflood assessments had not been completed at the time of this report). Initial results of this economic assessment indicate continuous CO_2 injection without gas processing has merit and support continued evaluation of algal-mound reservoirs as potential CO_2 flood candidates. The economic assessment of CO_2 flooding included:

- Purchase versus lease of the main injection compressor.
- Use of a membrane gas purification system to separate CO_2 from hydrocarbon components of the produced gas. The CO_2 steam was re-injected into the reservoir and the hydrocarbon gas was used for fuel to power the compressor and sold.
- Comparison of economics for all cases using a minimum and maximum estimate for the length of a CO_2 supply surface line to the site and the cost of its construction.

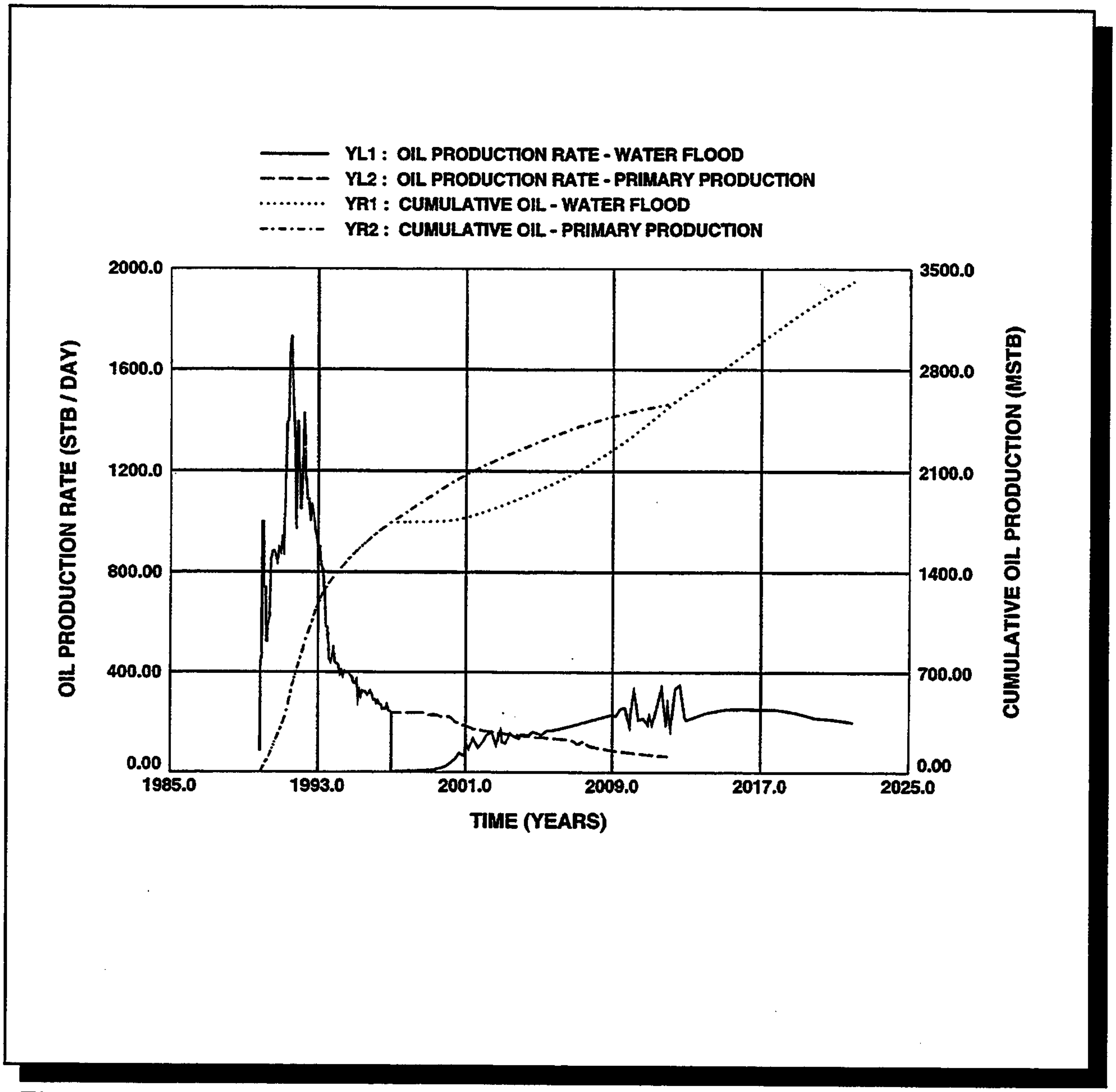

Figure 3.9. Oil recovery - primary versus waterflood, Anasazi field.

Production data and injection gas requirements, including CO_2 make-up purchases, from case B information were used to assess (see section 3.3.1), from an economic standpoint, the financial merits of CO_2-flood with a 8.0 MMCFGPD (226,560 m^3/d) total injection rate commencing January 1, 2000. The results using two options are summarized in table 3.2. The economic assessment was conducted assuming the following conditions: (1) leased compressor (option 1 - $19,500/option 2 - $23,500 [same compressor with a different engine] for 12.6 years), (2) CO_2 supply line construction using the minimum costs option ($825,000), (3) no gas processing, and (4) cost sharing by the U.S.

Department of Energy (DOE). This assessment concludes that CO_2 flooding provides both an adequate flood response and an acceptable economic rate of return of 32 percent and a payout of 36 months. A discounted (10 percent) net present value of $5.9 million could be realized by implementing a CO_2 flood under the proposed conditions. Harken's capital outlay with DOE participation would be $1,493,000.

Table 3.2. Economic performance parameters for low injection rate from case B, Anasazi field.

Compressor Option	Before Tax NPV[1] (in thousands $)	Before Tax IRR[2] (%)	Payout Months	PI[3]
1	$5,930	32	36	10.4
2	$5,300	30	48	9.7

[1]NPV = net present value assuming a 10% cost of capital
[2]IRR = internal rate of return
[3]PI = profitability index

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4. GEOSTATISTICAL MODELING AND RESERVOIR ENGINEERING ANALYSIS: RUNWAY FIELD

Douglas M. Lorenz and William E. Culham; REGA Inc.
and
Thomas C. Chidsey, Jr.; Utah Geological Survey

The Desert Creek carbonate-mound buildup reservoir at Runway field (figure 1.1) was selected for a follow-up study to the completed Anasazi field reservoir assessment both for comparison with those results, and also as a more promising candidate for a Phase II pilot demonstration due to the closer proximity of Runway to potential sources of injectable CO_2. The pipeline that provides CO_2 for the Greater Aneth field CO_2 flooding program is 0.5 miles (0.8 km) southeast of Runway field. The Runway mound complex also has a long production history (more than seven years), a large amount of hard data for reservoir characterization (three logged wells, two of which are also cored through the Desert Creek zone), and has considerable seismic coverage. The reservoir also is more gas rich than the other project fields and consists of both phylloid-algal and bryozoan buildup facies (Chidsey, T.C., Jr., Eby, D.E., and Lorenz, D.M., 1996).

4.1 Runway Field Overview - Location, Geometry, and General Stratigraphy

The discovery well for the Runway field, the Runway No. 10-G-1 (SW1/4NE1/4 section 10, T. 40 S., R. 25 E., Salt Lake Base Line), was completed in 1990 at an IPF of 825 BOPD (131 m^3/d) and 895 MCFGPD (25,346 m^3/d) from commingled Desert Creek and upper Ismay zone production. The Runway prospect was identified as a seismic anomaly located on the upthrown edge of a basement-involved, Mississippian-age normal fault which was a topographic high during Paradox Formation time. Cumulative production from Runway field is 780,272 BO (124,063 m^3) and 2.51 BCFG (0.7 billion m^3) as of July 1, 1997 (Utah Division of Oil, Gas and Mining, 1997). Estimated primary recovery from the field was 720,000 BO (114,480 m^3) and 2.83 BCFG (0.08 billion m^3) (Chidsey and others, 1996).

The detailed combined structure/isopach map of the Desert Creek zone in the Runway area (figure 4.1) shows a Desert Creek mound buildup more than 50 feet (15 m) thick, based on well log and seismic information. Runway field is somewhat larger (193 acres [78 ha]) than Anasazi (165 acres [67 ha]) with a thicker average net pay (72 feet [22 m] and 57 feet [17 m], respectively) but lower average net pay porosity (11.9 percent and 14.1 percent, respectively) (Chidsey and others, 1996a, b). Three additional dry holes previously drilled nearby have provided off-mound thickness, lithology, and porosity data. Runway field is a lenticular, west- to east-northeast-trending lobate mound, 0.9 miles (1.5 km) long and 0.5 miles (0.8 km) wide (Chidsey and others, 1996a).

The reservoir consists of a combination of bryozoan-buildup and phylloid-algal-buildup intervals. The presence of two buildup types at Runway field suggests that the water depth changed as the carbonate deposits built up over the fault-controlled paleohigh. A variety of carbonate

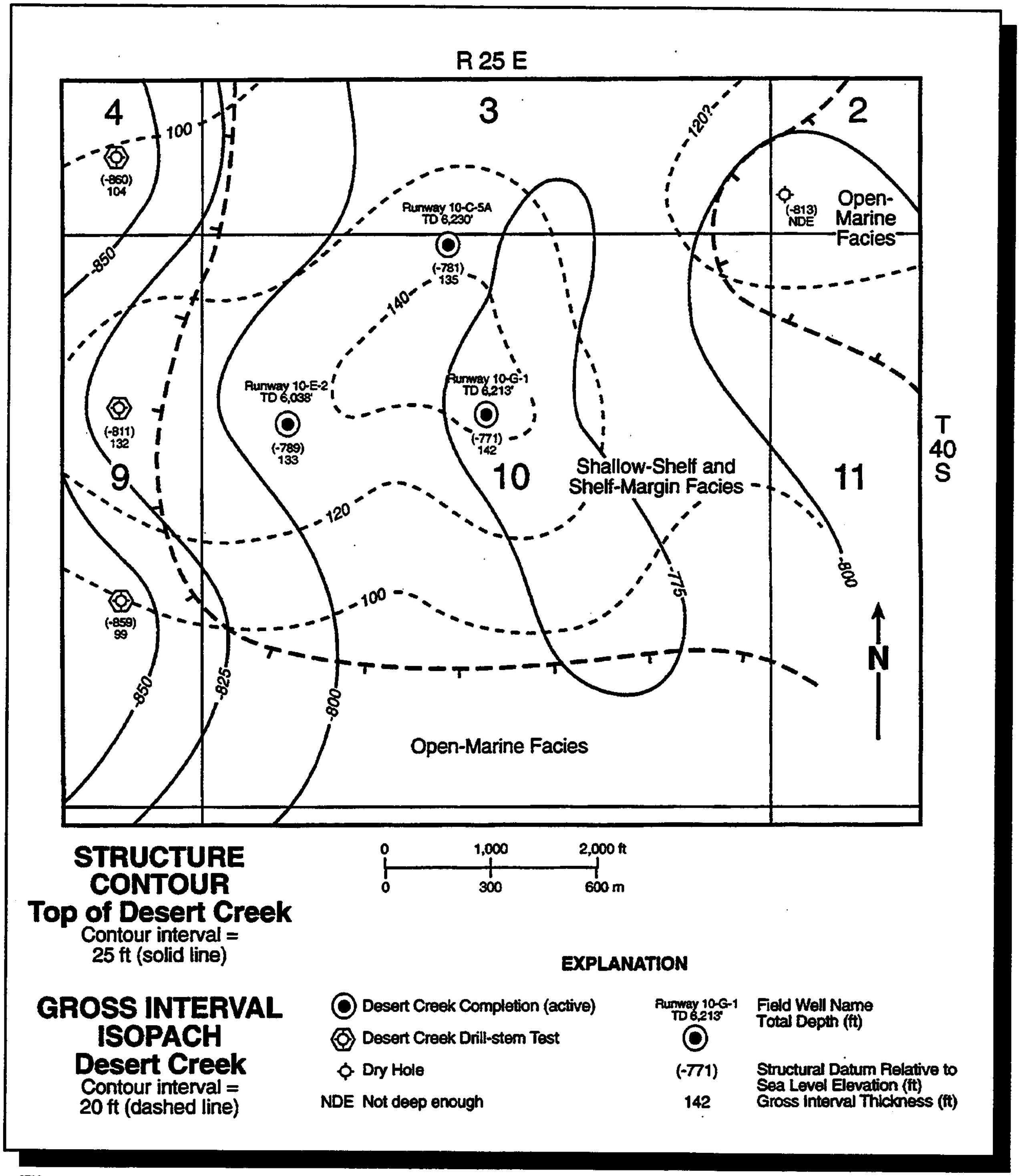

Figure 4.1. Combined Desert Creek zone structure contour and gross interval isopach map, Runway field, San Juan Co. Utah (Chidsey and others, 1996).

facies is encountered in all three Runway wells which causes a high degree of spatial heterogeneity in reservoir properties.

Conventional cores from Runway field contain 15 to 19 lithologic units (figure 2.5). Some units exhibit partial to complete dolomitization; late anhydrite plugging is also present. Pore types in these rocks include moldic, intercrystalline, and vuggy. At least three flooding surfaces are present and are likely to be barriers or baffles to fluid flow. Extensive karstification and solution-collapse brecciation has occurred in some of the middle to upper units.

The principal Desert Creek reservoir lithotypes in the bryozoan-dominated interval are bindstones and framestones. The principal reservoir lithotypes in the phylloid-algal-mound interval are porous lime bafflestones with some grainstones. Both carbonate buildups are interbedded with low-permeability wackestones and mudstones. Dolomitization has enhanced the reservoir potential of several lithotypes.

4.2 Reservoir Geostatistical Modeling

As at Anasazi field, significant heterogeneity in both the lithotypes and the reservoir properties at Runway field requires development of a multi-stage procedure for incorporating the variation known to exist in conventional cores from the field into the reservoir geostatistical model. Geostatistical modeling of the Runway reservoir incorporates unit thicknesses, flooding surfaces, and lithotypes observed in the core. Work on the field model during the year included: (1) developing foot-by-foot vertical variograms and spatial models for Desert Creek porosity and permeability, (2) mapping six time-structure surfaces, (3) correlating between wells using geophysical logs and updated core interpretations, (4) determining the bulk proportions of limestone, dolomite, anhydrite, and porosity in the Desert Creek and upper Ismay zones in field and peripheral wells, and (5) geostatistically generating reservoir properties and interval thicknesses between wells.

Although three-dimensional seismic data have not been acquired over Runway field, two sets of closely spaced swath lines have provided the data for defining the geometry and average porosity of the Desert Creek carbonate mound reservoir with greater confidence than was possible at Anasazi. The carbonate-mound buildup isolith map (figure 4.2) was obtained by time-depth conversion on the top and base of the Desert Creek zone, tied to the three Runway wells plus six other wells in the vicinity. The thickness of the smoothly varying anhydrite at the top of the Desert Creek was subtracted to produce the carbonate reservoir isolith map. Average porosity (figure 4.3) was obtained from the seismic amplitude data. The porosity grid was also tied to the wells used in the isolith map and thickness effects were deleted. Figures 4.2 and 4.3 clearly depict the Runway carbonate-mound buildup, with the best reservoir quality (as represented by average porosity) closely corresponding to the buildup areas.

The three-fold subdivision of the Anasazi carbonate-mound buildup into platform, mound-core, and supra-mound intervals is also present at Runway, although the carbonate lithotypes are somewhat different. At least three distinct mound-building episodes by phylloid algae, followed by fenestrate bryozoa, and phylloid algae again, are represented in the Runway reservoir. Primary carbonate stratigraphy is less heterogeneous at Runway than at Anasazi, although the supra-mound interval in the thickest parts of the mound has undergone a great deal of secondary solution collapse brecciation, as seen in core from the Runway No. 10-E-2 well.

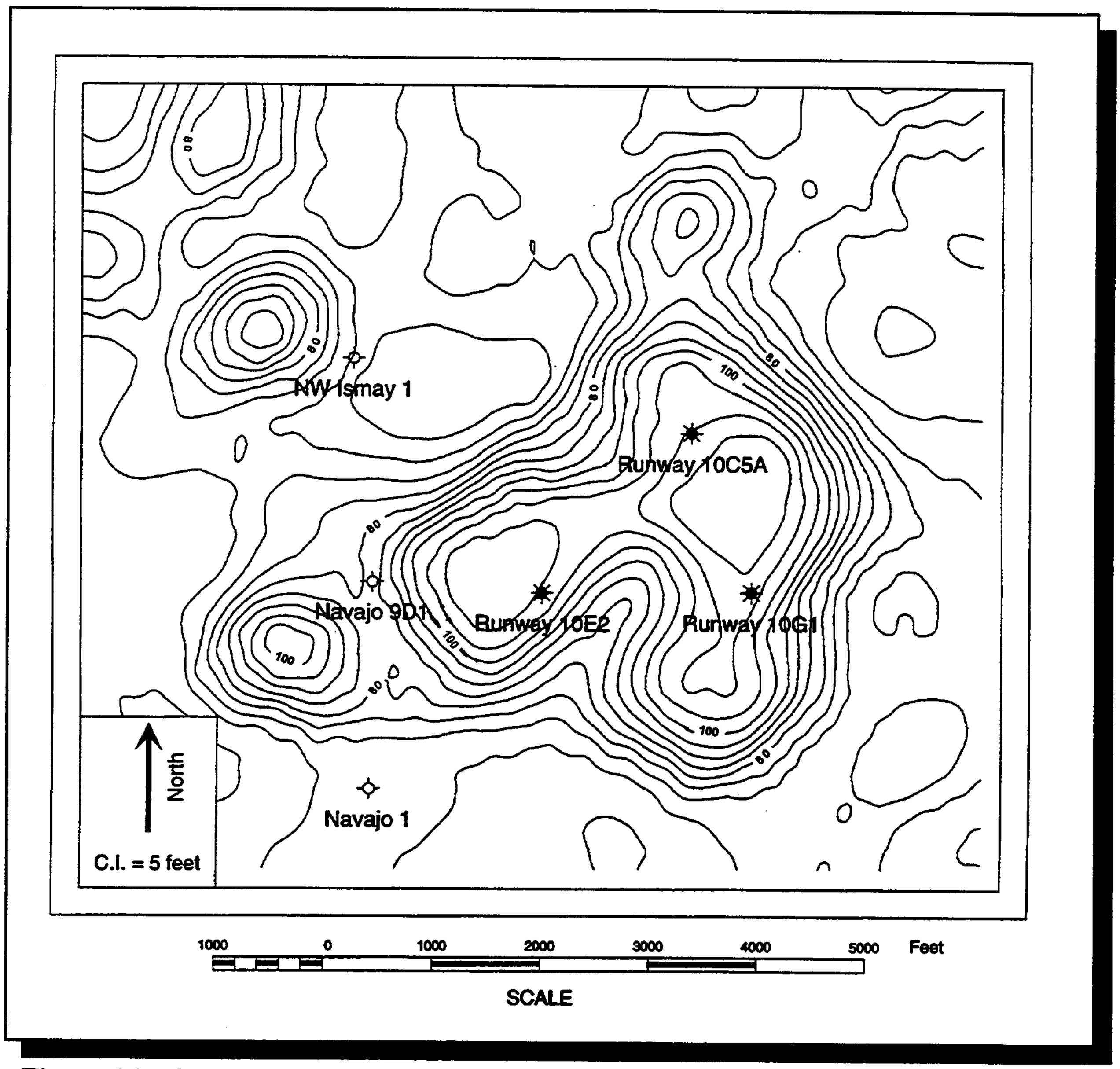

Figure 4.2. Carbonate isolith map of the Desert Creek reservoir, Runway field.

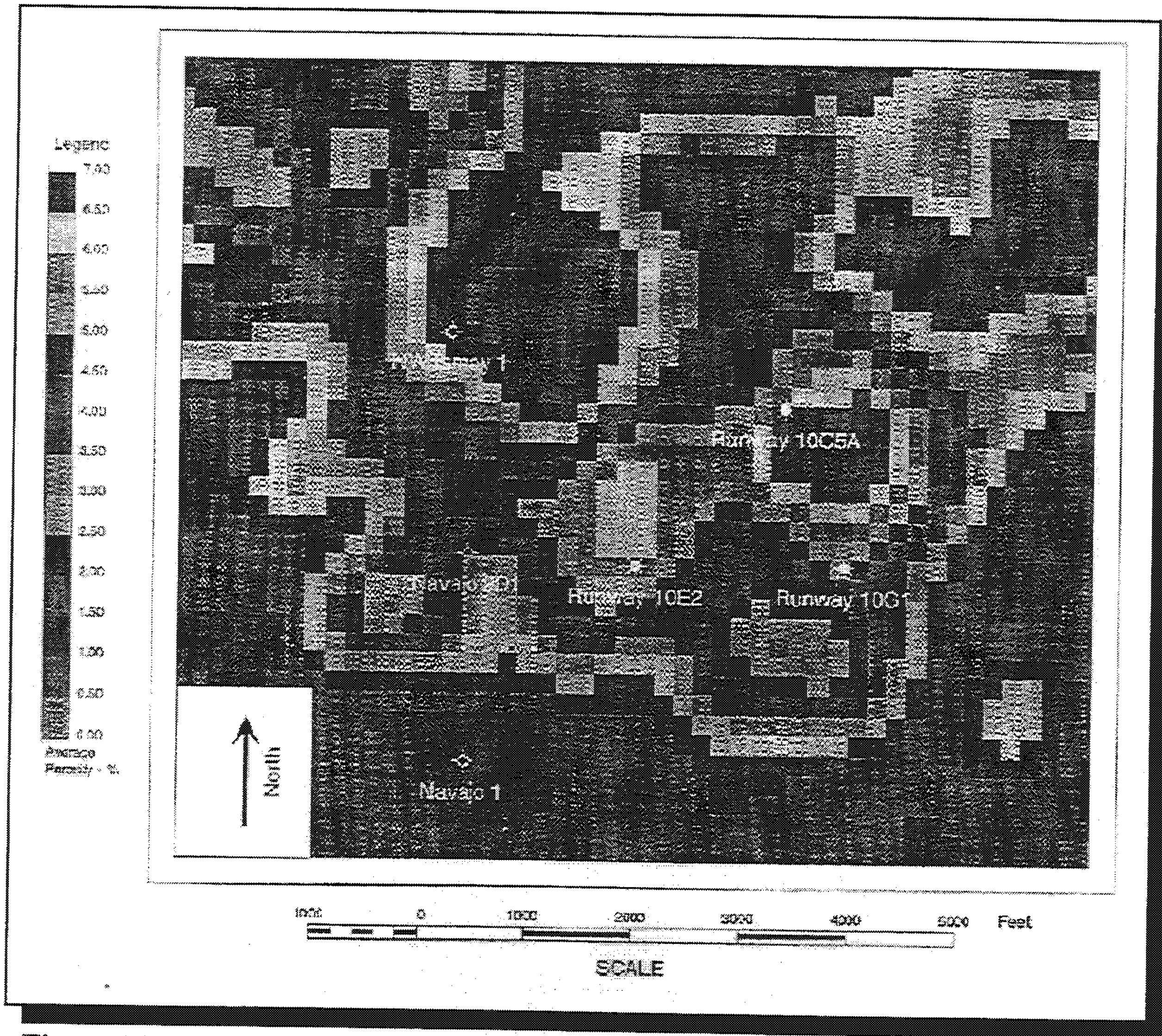

Figure 4.3. Average porosity grid of the Desert Creek reservoir, Runway field.

The Runway reservoir model consists of a 1,548-block areal grid (43 columns, 36 rows), with each square grid block measuring 180 feet (55 m) on a side. As at Anasazi, the Desert Creek carbonate interval was subdivided into 50 equal-thickness layers, ranging from 1.3 feet (0.4 m) thick in the off mound areas to 2.3 feet (0.7 m) in the thickest part of the mound (Chidsey, 1997a). Because one well (Runway No. 10-G-1) also produces from the upper Ismay zone of the Paradox Formation, two additional layers are included in the model, one 60-foot (18.3-m) layer for the Ismay carbonate reservoir, and a 115-foot (35-m) inactive layer representing the average non-reservoir interval between the top of the Desert Creek carbonates and the base of the upper Ismay over Runway field.

A total of nine lithotypes were recognized from the Runway cores, which formed the basis for generating an architectural model of the Desert Creek reservoir, using a boolean marked-point process for lithotype emplacement between the wells. These reservoir partitions were then populated with porosities, using layer-averaged statistical distributions obtained from the well log and core data. The spatial distribution of porosity was fitted to the average porosity grid (figure 4.3) using a constrained stochastic block-exchange procedure (simulated annealing). A total of 50 equally probable realizations of this hybrid model have been generated, and horizontal and vertical permeabilities estimated using porosity/permeability correlations from core data. These 50 cases are currently being ranked according to a statistical measure of reservoir connectivity. A subset of three or four realizations representing the predominant types of connectivity will be selected, the Desert Creek interval vertically upscaled to 10 layers, and short simulation sensitivity runs will be carried out to evaluate the impact of heterogeneity on reservoir behavior. The most representative of these cases will then be selected for conducting the flow-simulation history match and reservoir performance predictions.

4.3 Reservoir Engineering Analysis

Two processes, with appropriate variations, are being evaluated (from a standpoint of oil recovery and economics) for implementing in a field pilot or demonstration project in Runway field. The first is the waterflood, which can use fluid properties suitable for black oil reservoir simulation studies. The second recovery process is CO_2-gas injection. Since CO_2 processes require composition data, more comprehensive fluid-property data was needed. Prior to evaluation of the two processes it will be necessary to model and history match the primary production phase of the Runway reservoir. Thus, the following general class of simulation studies will be performed:

1. primary depletion (history match),
2. waterflood, and
3. CO_2 flood.

A compositional simulation approach is being used to model all three processes. A compositional approach properly accounts for oil vaporization (high API gravity oils) during primary depletion and will provide the correct oil compositions to subsequently assess CO_2-flooding potential.

During this third year of the project, team members performed the following reservoir engineering analysis of Runway field:

1. evaluated oil-brine and gas-oil capillary pressure data and analyzed Runway well tests,

2. completed geologic model development of the Runway reservoir units for use in reservoir simulation studies including initiation of one- and two-dimensional mechanistic simulation runs to identify CO_2 process minimum miscibility pressure and displacement - mass transfer mechanisms, and

3. completed the first phase of the full field, three-dimensional Runway reservoir simulation model, and began history matching of Runway field primary production and the reservoir performance prediction phase of the simulation study.

4.3.1 Oil-brine and Gas-oil Capillary Pressure Data and Well Tests

Oil-brine and gas-oil capillary pressure data analysis employed ultra-centrifuge technology. The ultra-centrifuge data are being used to determine relative permeability data for the bryozoan bindstone/framestone facies. This data will supplement previous sets of relative permeability generated for the Anasazi reservoir (Chidsey, 1997b).

All well tests conducted on Runway wells have been analyzed using contemporary well test analysis technology. In general, each interval test from all three Runway wells behaved like a homogeneous system utilizing either fully penetrating and/or partially penetrating well models. The one exception was the zone 4 test from the Runway No. 10C-5A well. This required the use of a two-layer model to match observed data. Figures 4.4 and 4.5 illustrate the excellent agreement between field data and model predictions for the zone 2 test from the Runway No. 10-E-2 well. Reservoir parameters used for the model are shown on the figures. All other tests had similar quality matches.

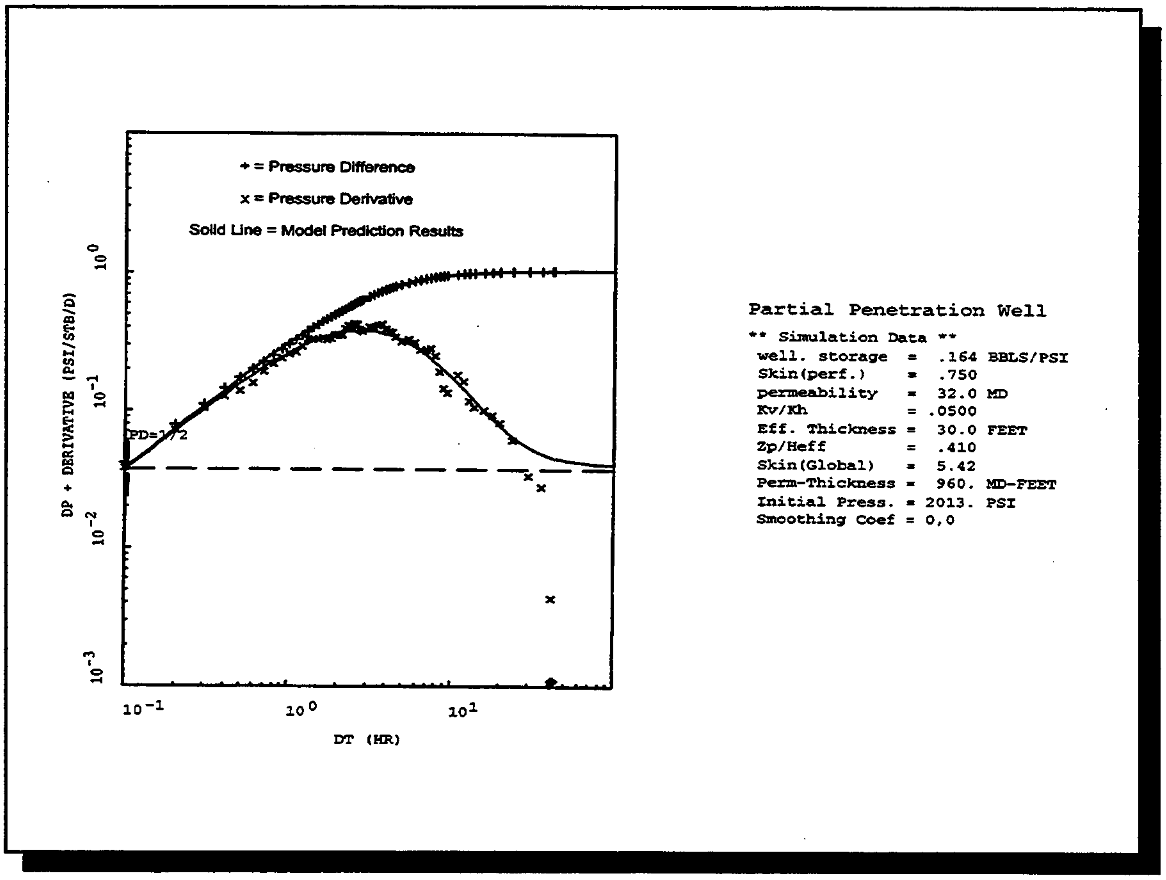

Figure 4.4. Runway No. 10-E-2 well, zone 2 test pressure derivative and pressure difference match, Runway field.

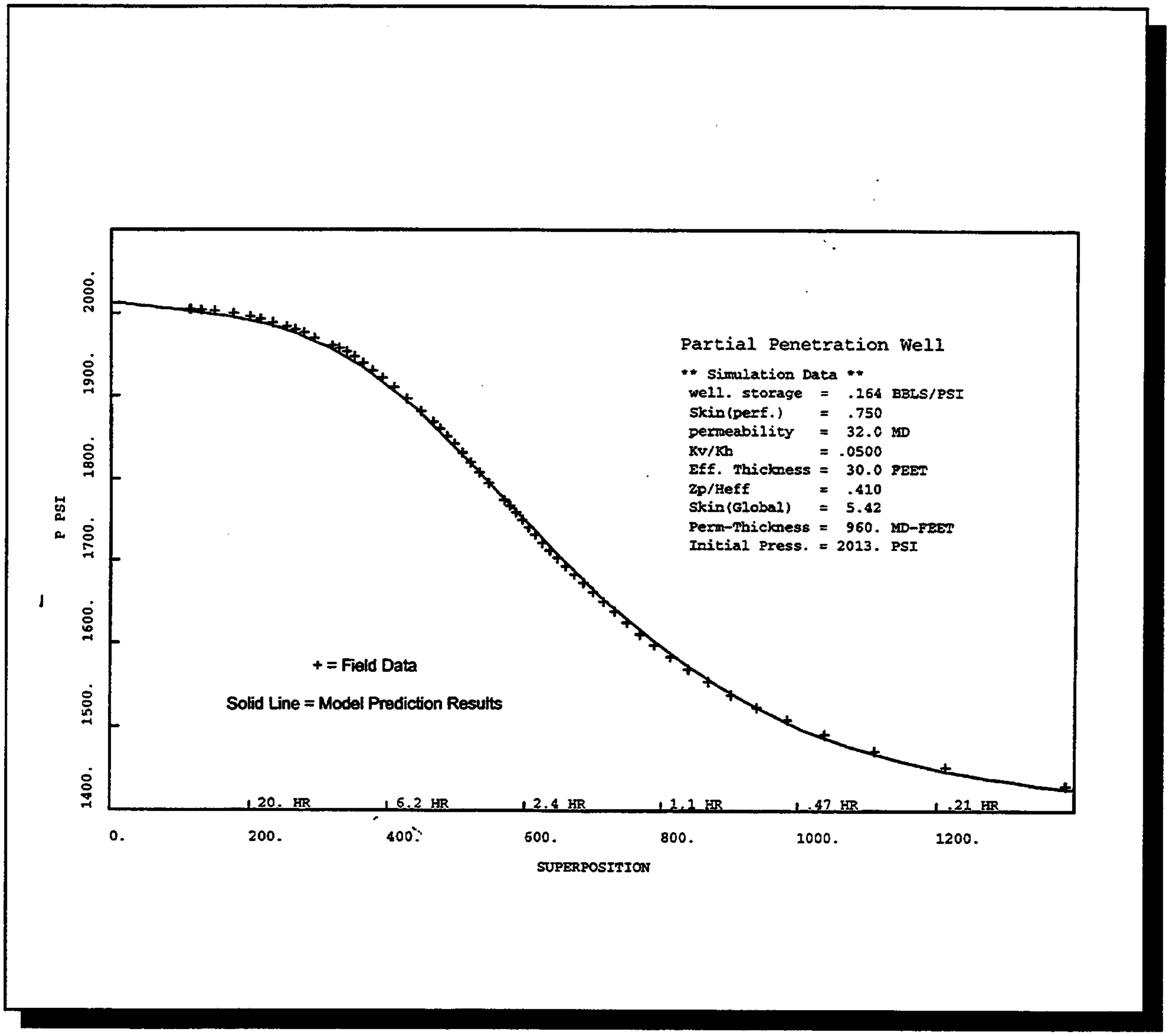

Figure 4.5. Runway No. 10-E-2 well, zone 2 test superposition plot match, Runway field.

4.3.2 History Matching and Reservoir Performance Prediction

The history matching of the primary production phase of the Runway field is based on one of the geostatistical realization of the reservoir geologic model. History matching involves the input of historical well/field oil production data with the predicted gas production and reservoir pressure being matched to well/field observed data. Because of the geometric and lithologic complexity of the Runway reservoir, a substantial history matching effort has been required. A large number of reservoir parameters and reservoir parameter combinations was investigated to match historical gas production and well to well interaction present during the primary reservoir production phase. Reservoir and fluid properties investigated include many different combinations of these variables:

1. reservoir size/volume,

2. reservoir permeability (both horizontal and vertical) and porosity and their distribution areally as well as between the principal reservoir facies,

3. gas relative permeability,

4. solution gas content of the original reservoir fluid,

5. rock compressibility,

6. volume of different reservoir facies,

7. transmissibility between the principal mound-core (limestone) and supra-mound (dolomite) intervals (Chidsey and others, 1996), and

8. the use of reservoir unit barriers or transmissibility reduction areas.

No local (near the wellbore) changes are being employed to match production. Reservoir description changes on a regional basis are used to match the reservoir-wide fluid movement occurring within the system which in turn controlled local well behavior.

4.4 References

Chidsey, T.C., Jr., 1997a, compiler, Increased oil production and reserves utilizing secondary/tertiary recovery techniques on small reservoirs in the Paradox basin, Utah - annual report: U.S. Department of Energy, DOE/BC/14988-9, 65 p.

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Chidsey, T.C., Jr., Eby, D.E., Groen, W.G., Hartmann, Kris, and Watson, M.C., 1996a, Runway field, *in* Hill, B.G., and Bereskin, S.R., editors, Oil and gas fields of Utah: Utah Geological Association 22 (Addendum), non-paginated.

Chidsey, T.C., Jr., Eby, D.E., Groen, W.G., Hartmann, Kris, and Watson, M.C., 1996b, Anasazi field, *in* Hill, B.G., and Bereskin, S.R., editors, Oil and gas fields of Utah: Utah Geological Association 22 (Addendum), non-paginated.

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Utah Division of Oil, Gas and Mining, 1997, Oil and gas production report, June 1997: non-paginated.

5. TECHNOLOGY TRANSFER

Thomas C. Chidsey, Jr.; Utah Geological Survey

The UGS is the Principal Investigator and prime contractor for three government-industry cooperative petroleum-research projects including the Paradox basin project. These projects are designed to improve recovery, development, and exploration of the nation's oil and gas resources through use of better, more efficient technologies. The projects involve detailed geologic and engineering characterization of several complex heterogeneous reservoirs. The Class II Paradox basin and the Class I Bluebell field (Uinta Basin) projects will include practical oil-field demonstrations of selected technologies. The third project involves geological characterization and reservoir simulation of the Ferron Sandstone on the west flank of the San Rafael uplift as a surface analogue of a fluvial-dominated deltaic reservoir. The U.S. Department of Energy (DOE) and multidisciplinary teams from petroleum companies, petroleum service companies, universities, private consultants, and State agencies are co-funding the three projects.

The UGS will release all products of the Paradox basin project in a series of formal publications. These will include all the data as well as the results and interpretations. Syntheses and highlights will be submitted to refereed journals as appropriate, such as the American Association of Petroleum Geologists (AAPG) Bulletin and Journal of Petroleum Technology, and to trade publications such as the Oil and Gas Journal. This information will also be released through the UGS Petroleum News, Survey Notes, and on the project Internet home page.

Project materials, plans, and objectives were displayed at the UGS booth during the 1997 annual national convention of the AAPG in Dallas, Texas; and the 1997 AAPG Rocky Mountain Section annual meeting in Denver, Colorado. Three to four UGS scientists staffed the display booth at these events. An abstract were submitted for technical presentations at the 1998 AAPG national meeting. Project displays will be included as part of the UGS booth at professional meetings throughout the duration of the project.

5.1 Utah Geological Survey *Petroleum News*, *Survey Notes*, and Internet Web Site

The purpose of the UGS *Petroleum News* newsletter is to keep petroleum companies, researchers, and other parties involved in exploring and developing Utah energy resources, informed of the progress on various energy-related UGS projects. The UGS *Petroleum News* contains articles on: (1) DOE-funded and other UGS petroleum project activities, progress, and results, (2) current drilling activity in Utah including coalbed methane development, (3) new acquisitions of well cuttings, core, and crude oil at the UGS Sample Library, and (4) new UGS petroleum publications. The purpose of Survey Notes is to provide nontechnical information on contemporary geologic topics, issues, events, and ongoing UGS projects to Utah's geologic community, educators, state and local officials and other decision makers, and the public. Survey Notes is published three times yearly and Petroleum News is published semi-annually. Single copies are distributed free of charge and reproduction (with recognition of source) is encouraged. The UGS maintains a database which includes those companies or individuals specifically interested in the Paradox basin project (over 295 as of February 1998) or other DOE-sponsored projects.

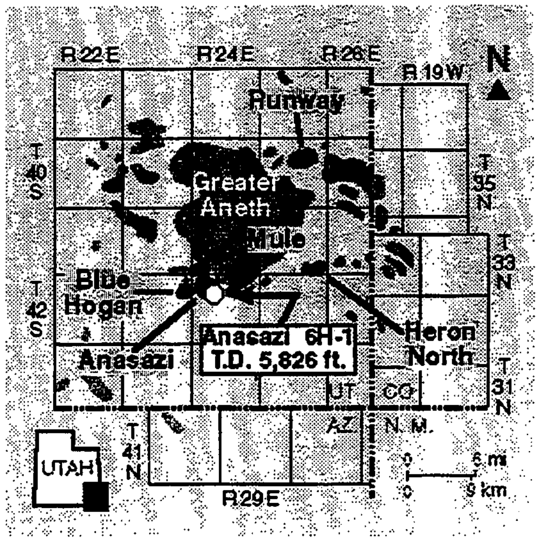
The UGS established a web site on the Internet, http://www.ugs.state.ut.us/. This site includes a page under the heading Economic Geology Program, which describes the UGS/DOE cooperative studies (Paradox basin, Ferron Sandstone, and Bluebell field), contains the latest issue of Petroleum News, and has a link to the U.S. Department of Energy web site. Each UGS/DOE cooperative study also has its own separate page on the UGS web site. The Paradox basin project page (http://www.ugs.state.ut.us/paradox.htm) contains: (1) a project location map, (2) a description of the project, (3) a list of project participants and their postal addresses and phone numbers, (4) executive summaries from the first and second annual reports, (5) each of the project Quarterly

Utah Geological Survey

Paradox Basin - DOE Class II Study

Reports

- Project description
- Project participants
- First Annual Technical Report
- Second Annual Technical Report
- Quarterly Technical Progress Reports:
  - 1995 1st Quarterly Report
  - 1995 2nd Quarterly Report
  - 1995 3rd Quarterly Report
  - 1995 4th Quarterly Report
  - 1996 1st Quarterly Report
  - 1996 2nd Quarterly Report
  - 1996 3rd Quarterly Report
  - 1996 4th Quarterly Report
  - 1997 1st Quarterly Report
  - 1997 2nd Quarterly Report
  - 1997 3rd Quarterly Report



References

- Publications resulting from the study

For more information on the Paradox Basin Project, contact Tom Chidsey, (801) 537-3364, email: nrugs.tchidsey@state.ut.us. For copies of reports with tables and figures, contact Roger L. Bon, (801) 537-3363, email: nrugs.rbon@state.ut.us.

Bluebell Field Project / Ferron Sandstone Project
Petroleum News / Economic Geology Program

UGS Home

Figure 5.1. The Paradox basin project page, http://www.ugs.state.ut.us/paradox.htm, from the UGS Internet web site.

Technical Progress reports, and (6) a reference list of all publications that are a direct result of the project (figure 5.1).

5.2 Presentations

The following technical and nontechnical presentations were made during the year as part of the Paradox basin project technology transfer activities. These presentations described the project in general and gave detailed information on the reservoir characterization, exploration trends, geostatistics, reservoir models, and simulations.

"Reservoir Modeling of the Anasazi Carbonate Mound, Paradox Basin, Utah" by D.M. Lorenz, W.E. Culham, T.C. Chidsey, Jr., and Kris Hartmann; American Association of Petroleum Geologists Annual Convention, Dallas, Texas, April 1997.

"Class II Oil Project - Increased Oil Production and Reserves Utilizing Secondary/Tertiary Recovery Techniques on Small Reservoirs in the Paradox Basin, Utah" by T.C. Chidsey, Jr., U.S. Department of Energy, Contractors Review Meeting, Houston, Texas, June 1997.

"Heron North Field, Navajo Nation, San Juan County, Utah - A Case Study for Small Calcarenite Carbonate Buildups" by T.C. Chidsey, Jr., and D.E. Eby; American Association of Petroleum Geologists Rocky Mountain Section Meeting, Denver, Colorado, August 1997.

"Heron North Field, Navajo Nation, San Juan County, Utah: A Case Study For Small Calcarenite Carbonate Reservoirs" by T.C. Chidsey, Jr.; Utah Geological Association monthly meeting, Salt Lake City, Utah, November 1997.

5.3 Project Publications

Chidsey, T.C., Jr., 1997, compiler, Increased oil production and reserves utilizing secondary/tertiary recovery techniques on small reservoirs in the Paradox basin, Utah - annual report: U.S. Department of Energy, DOE/BC/14988-9, 65 p.

Chidsey, T.C., Jr., and Eby, D.E., 1997, Heron North field, Navajo Nation, San Juan County, Utah - a case study for small calcarenite carbonate buildups [abs]: American Association of Petroleum Geologists Bulletin, v. 81, no. 7, p. 1220.

Harty, K.M., 1997, Harken is first contributor to the UGS Sample Library trust fund: Utah Geological Survey, Survey Notes, v. 29, no. 2, p. 5.

Lorenz, D.M., Culham, W.E., Chidsey, T.C., Jr., and Hartmann, Kris, 1997, Reservoir modeling of the Anasazi carbonate mound, Paradox basin, Utah [abs.]: American Association of Petroleum Geologists Annual Convention, Official Program, v. 6, p. A71-72.

Utah Geological Survey, 1997a, Paradox basin minerals symposium heralded as a great success: Utah Geological Survey, Survey Notes, v. 29, no. 3, p. 8-9.

---1997b, Oil demonstration programs move into advanced phases: Utah Geological Survey, Survey Notes, v. 30, no. 1, p. 10-11.

---1997c, Paradox project moves to horizontal drilling: Utah Geological Survey, Petroleum News (April), p. 11-15.

Utah Geological Survey, 1998, Paradox project completes horizontal drilling, delineates potential calcarenite trend: Utah Geological Survey, Petroleum News (January), p. 10-14.

U.S. Department of Energy, 1997a, Increased oil production and reserves utilizing secondary/tertiary recovery techniques on small reservoirs in the Paradox basin, Utah, *in* Contracts for field projects and supporting research on enhanced oil recovery, reporting period January-March 1996: Progress Review No. 86, DOE/BC--96/2, p. 93-97.

---1997b, Increased oil production and reserves utilizing secondary/tertiary recovery techniques on small reservoirs in the Paradox basin, Utah, *in* Contracts for field projects and supporting research on enhanced oil recovery, reporting period April-June 1996: Progress Review No. 87, DOE/BC--96/3, p. 64-68.

---1997c, Increased oil production and reserves utilizing secondary/tertiary recovery techniques on small reservoirs in the Paradox basin, Utah, *in* Contracts for field projects and supporting research on enhanced oil recovery, reporting period July-September 1996: Progress Review No. 88, DOE/BC--96/4, p. 79-83.